

AR57



Aiming for Value

1998 ANNUAL REPORT

NOTICE OF ANNUAL GENERAL MEETING

The Annual General Meeting of shareholders will be held on May 13, 1999 at 3:00 pm at the Westin Hotel, 320 - 4th Ave. S.W., Calgary, Alberta. All shareholders and other interested parties are invited to attend.



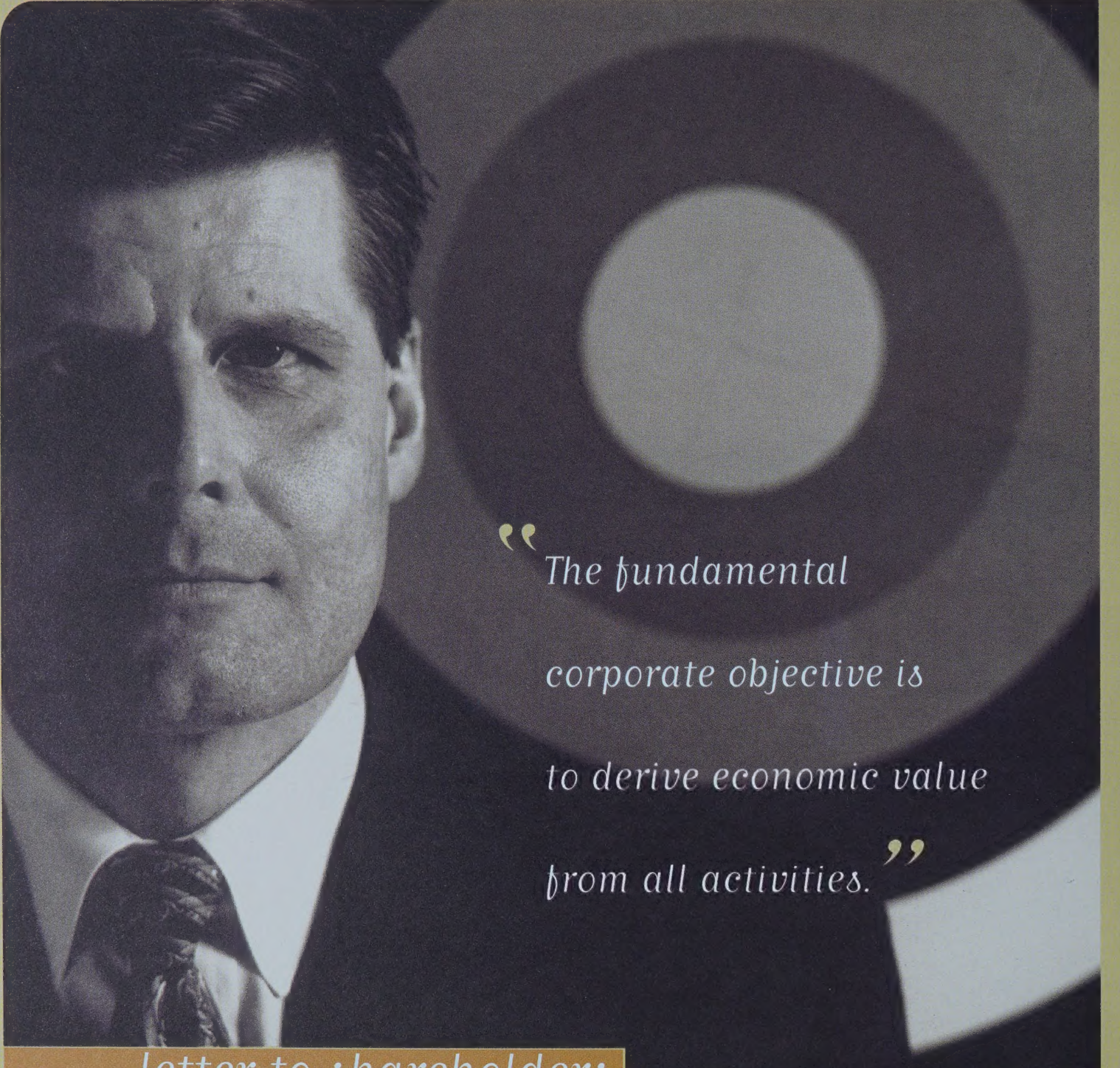
C O R P O R A T E P R O F I L E

PETROMET Resources Limited is engaged in exploration, development, acquisition, and production of oil and natural gas. Its headquarters are in Calgary, Alberta. Petromet is highly focused on natural gas within West Central Alberta. The Company operates and controls its most significant assets including extensive gathering system and processing infrastructure and large holdings of undeveloped land. The fundamental corporate objective is to derive economic value from all activities. Petromet's common shares are listed under the symbol PNT and its convertible debentures are listed under the symbol PNT.DB on The Toronto Stock Exchange. Petromet is also listed on The Nasdaq Stock Market under the symbol PNTGF.

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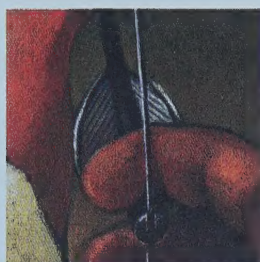
highlights

YEAR ENDED DECEMBER 31	1998	1997
FINANCIAL (\$ millions, except per share amounts)		
Revenue	39.4	33.9
Net income	2.2	4.4
Per share	0.05	0.11
Cash flow	21.5	20.6
Per share	0.49	0.53
Capital expenditures	66.4	49.6
Long-term debt, net of working capital	83.8	46.1
Shareholders' equity	107.6	97.9
Total assets	214.3	163.2
Common shares outstanding (millions)		
Basic	45.3	42.7
Weighted average	43.6	38.5
OPERATING		
Production		
Natural gas (mmcf/d)	43.7	37.2
Oil and NGL (bbls/d)	1,329	971
Oil equivalent (BOE/d)	5,702	4,691
Average prices		
Natural gas (\$/mcf)	1.92	1.85
Oil and NGL (\$/bbl)	16.21	23.42
Other income (\$/BOE)	0.42	0.29
Oil equivalent (\$/BOE)		
Revenue	18.92	19.82
Royalties, net of ARTC	2.65	3.39
Operating costs	2.35	2.07
Field netback	13.92	14.36
General and administrative costs	1.17	0.66
Current taxes	0.21	0.18
Operating netback	12.54	13.52
Cash interest	2.23	1.50
Cash flow from operations	10.31	12.02
Drilling activity		
Net wells	12	25
Success rate (%)	71	64
Net undeveloped land (000's acres)	580	520



*“The fundamental
corporate objective is
to derive economic value
from all activities.”*

letter to shareholders



NINETEEN ninety-eight was a pivotal year for Petromet. A new business plan founded on value creation principles is being executed under the leadership of Johannes (Jim) J. Nieuwenburg, who became President and Chief Executive Officer on May 13, 1998.

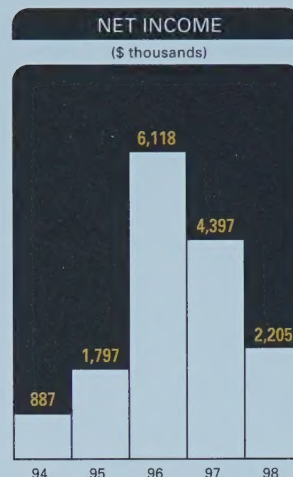
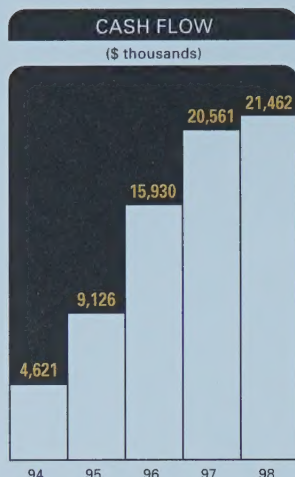
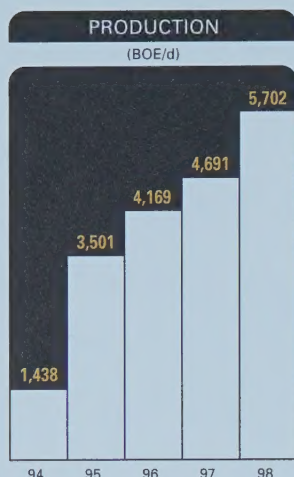
THE FUNDAMENTAL CORPORATE objective is to derive economic value from all activities. This will be done by exploiting and enhancing Petromet's considerable competitive advantages. The Company will remain focused on natural gas, with high ownership interests and control of its land and infrastructure. Petromet will strive to continue operating efficiently with a cost structure which is currently among the best in the Canadian industry. A more diverse approach to growth is being implemented, with greater emphasis on exploitation and acquisitions to complement the primary catalyst of growth from exploration. Acquisitions will be justified primarily by the identification of synergistic components and strategic fit. A portfolio of natural gas sales contracts will be systematically maintained to reduce the volatility

Petromet will strive to continue operating efficiently with a cost structure which is currently among the best in the Canadian industry.

of cash flows, provide predictable capital for reinvestment into economically attractive opportunities, and optimize debt leverage for the benefit of shareholders. A capital investment threshold consisting of a 13 percent internal rate of return has been established to provide a value adding margin over the cost of capital. Growth will be maximized by investing in the best projects which meet the criteria.

Petromet's intrinsic competitive advantages are being complemented by process improvements to sustain the Company's evolution and growth. Additional geo-technical, engineering, and business development staff have been employed. Business systems for short-term forecasting and long-term strategic planning have been created. A new reserves database which integrates project economics and depletion forecasts has been installed. Field data capture is being implemented to complement production engineering. A modern land and contracts system is being implemented. Natural gas price realizations are being managed through a risk management system.

Petromet's newly defined business principles and values are being reinforced through performance based compensation. Remuneration is now more directly linked to individual, team, corporate and share price performance. Key drivers have been identified to ensure that the Company's activities contribute to shareholder value. An appropriate balance between short-term and long-term compensation rewards has been implemented to target both profitable and sustainable growth.



OPERATING REVIEW

Production increased by 22 percent to a record 5,702 BOE per day. Growth accelerated throughout the year as fourth quarter production in 1998 increased by 41 percent compared to the same period

A capital investment threshold consisting of a 13 percent internal rate of return has been established to provide a value adding margin over the cost of capital.

in 1997. Natural gas continued to comprise the largest component of production at approximately 78 percent of oil equivalent production.

Production gains from all activities in the latter half of the year contributed to an improving cost structure. Low cost production, which was added at Bigstone from exploiting and acquiring and at Wild River from exploring, contributed to lowering operating costs to \$2.35 per BOE in 1998 compared to \$2.70 per BOE for the first half of the year. Likewise, administrative costs averaged \$1.17 per BOE for 1998 compared to \$1.48 per BOE for the first half of 1998.

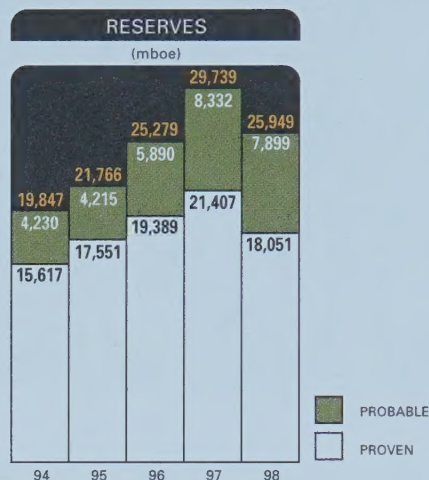
The \$20 million acquisition at Bigstone was an important accomplishment in 1998. The transaction allowed the Company to consolidate its interest in operated land and infrastructure. It demonstrated Petromet's acquisition strategy of capturing synergistic values such as the cost advantage it holds at Bigstone. Petromet expects to realize incremental

value from exploration and exploitation opportunities given its dominant ownership and control of infrastructure at Bigstone.

In 1998, Petromet took a proactive approach to ensure that reservoir performance, current economic conditions, and existing technology were realistically taken into account in its reported reserves. Consequently, proven reserves were reduced by 16 percent to 18.1 million BOE at year end 1998, net of revisions of 6.6 million BOE, additions of 5.4 million BOE, and production of 2.1 million BOE. The quality of Petromet's reported reserves improved as proven developed producing reserves now comprise 85 percent of total proven reserves versus 67 percent at year-end 1997.

FINANCIAL RESULTS

In a difficult year for oil and gas producers, Petromet was able to build operating momentum during 1998. Cash flow increased by four percent to a record \$21.5 million. Capital expenditures amounted to more than three times cash flow. Net income decreased by 50 percent to \$2.2 million, primarily as a result of lower prices for oil and NGL production, increased depletion and depreciation charges commensurate with the reserve revision, and increased



interest costs from higher levels of debt. By the fourth quarter of 1998, a positive shift in momentum was evident as cash flow increased by 46 percent to \$7.3 million, and the cash flow netback increased by four percent to \$11.83 per BOE of production compared to the same period in 1997.

OUTLOOK

Significant growth in production and cash flow is anticipated in 1999. Petromet has contracted a majority of its natural gas production in 1999 at fixed prices which correspond to a 20 percent increase on contracted volumes compared to average realizations in 1998. Natural gas prices may also benefit from tight supplies in North America due to reduced capital spending by industry, and from shrinking basis differentials caused by a surplus of export pipeline capacity in Western Canada. Petromet anticipates that it will achieve operating costs and netbacks in 1999 to rival the best in the Canadian oil and gas industry. Debt ratios are expected to improve significantly while investing a capital budget equivalent to available cash flow and maintaining balance sheet flexibility to take advantage of attractive opportunities. Generally weak conditions in the oil and gas industry are expected to reduce costs for exploration and development services and improve the potential to make complementary acquisitions. Petromet's exploration portfolio holds the potential for stellar growth should encouraging geological prospects be confirmed.

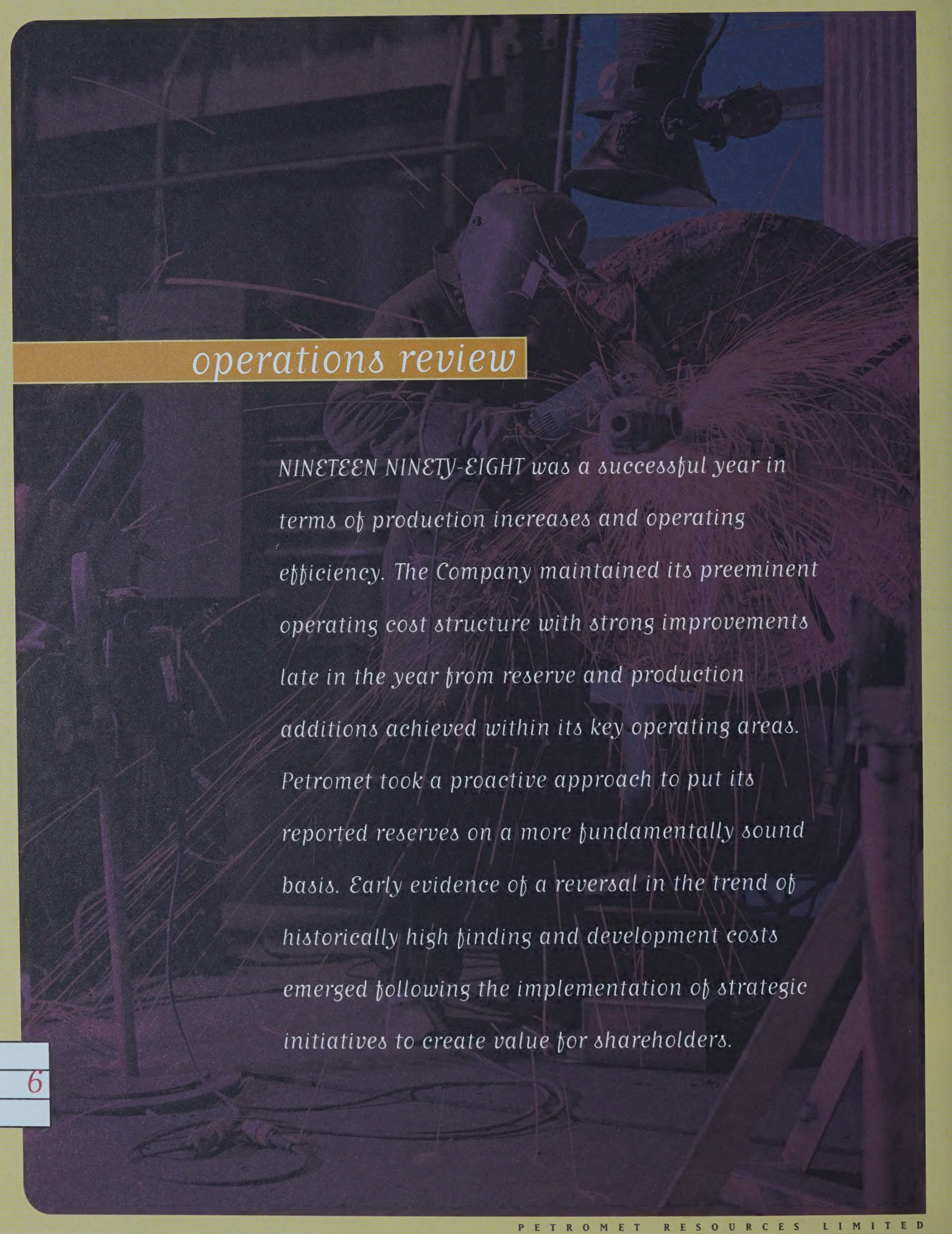
CORPORATE

At the 1999 Annual General Meeting, the Company will propose to reduce the size of the Board from eight to five members. Leaving the Board will be Laurie J. Smith who served as President and Chief Executive Officer for six years until May, 1998, and David H. Erickson, who served as Senior Vice President for ten years until January, 1999. Sharon A. Supple will also leave the Board while continuing her role as Chief Financial Officer. Petromet appreciates the valuable service and contributions to Petromet provided by these departing directors.

In a year of considerable transformation at Petromet, I am grateful to our employees for their effort, dedication, and achievements for the benefit of our shareholders.

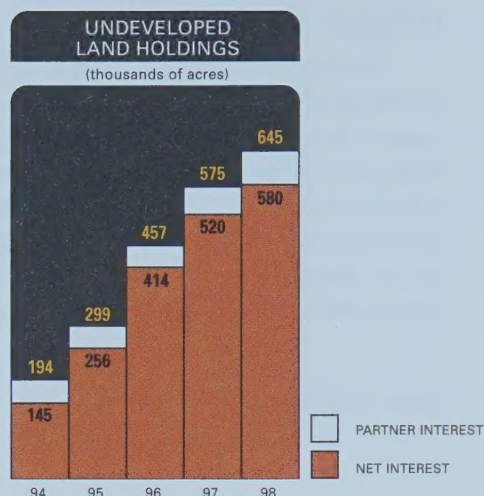
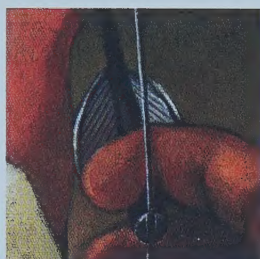
On behalf of the Board of Directors,

Johannes (Jim) J. Nieuwenburg,
President & Chief Executive Officer
March 24, 1999



operations review

NINETEEN NINETY-EIGHT was a successful year in terms of production increases and operating efficiency. The Company maintained its preeminent operating cost structure with strong improvements late in the year from reserve and production additions achieved within its key operating areas. Petromet took a proactive approach to put its reported reserves on a more fundamentally sound basis. Early evidence of a reversal in the trend of historically high finding and development costs emerged following the implementation of strategic initiatives to create value for shareholders.



LAND

Petromet has accumulated a relatively large inventory of undeveloped land within the natural gas prone area of West Central Alberta. Holdings of undeveloped land increased by 12 percent to 579,654 net acres, with an average working interest of 90 percent. Land acquisitions amounted to \$1.6 million in 1998 at an average cost of \$15 per acre, which compares favorably to an average industry cost of \$84 per acre for undeveloped land in Alberta. A significant proportion of Petromet's undeveloped land was acquired proactively during the early stages of exploration when acquisition costs were relatively low compared to current market values. Enhancement of the Company's land is being pursued through direct investment, leveraged participation in farmouts, and non-participation farmouts according to Petromet's determination of risk, geological prospectivity, capital requirements, and tenure.

Developed land increased by 14 percent to 48,556 net acres reflecting primarily an acquisition at Bigstone and the reclassification of undeveloped land through successful exploration and development. Petromet's average working interest in developed land, at 70 percent, is indicative of the high level of control that the Company continues to exert over its producing properties.

LAND HOLDINGS

ACRES	1998			1997		
	GROSS	NET	WI%	GROSS	NET	WI%
Developed	69,762	48,556	70	60,963	42,429	70
Undeveloped	645,126	579,654	90	574,577	519,699	90
Total	714,888	628,210	88	635,540	562,128	88

UNDEVELOPED LAND RECONCILIATION (ACRES)

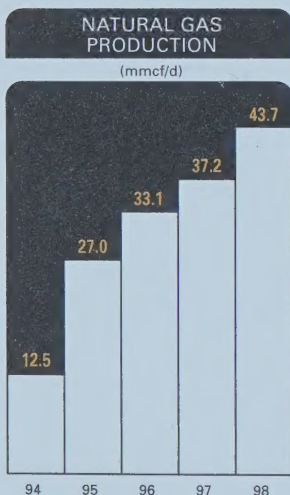
	GROSS	NET
December 31, 1997	574,577	519,699
Acquisitions	123,440	103,639
Dispositions	(3,680)	(1,696)
Expiries and reallocations to developed	(49,211)	(41,988)
December 31, 1998	645,126	579,654

DRILLING ACTIVITY

Petromet participated in 14 gross wells (12 net wells) in 1998. All of the Company's drilling was operated by Petromet. The drilling success rate increased to 71 percent in 1998 compared to 64 percent in 1997. Drilling resulted in seven natural gas wells, three oil wells, and four dry holes. Petromet's average working interest was 84 percent. In 1998, the Company drilled fewer wells at higher working interests to greater average depths with a higher success rate than in the past several years. During 1998, the Company's drilling strategy evolved to drill more selectively with greater reliance on geological and geophysical indicators of targets sufficiently large enough to meet the economic threshold. Evidence of lower costs for future drilling, due to generally weak industry conditions, became strongly apparent by the end of 1998.

DRILLING ACTIVITY

	1998		1997	
	GROSS	NET	GROSS	NET
Natural gas	7	6	14	11
Oil	3	3	6	5
Dry	4	3	11	9
Total	14	12	31	25
Success rate		71%		64%
Average working interest		84%		80%

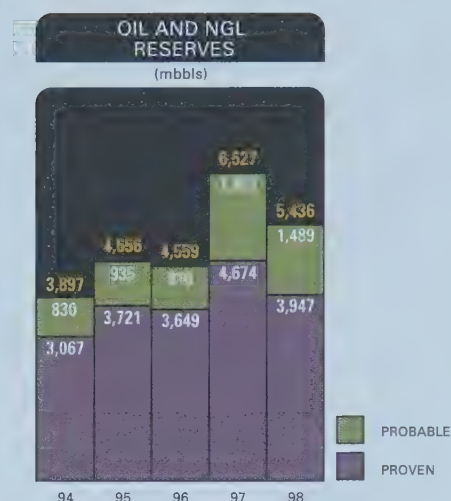
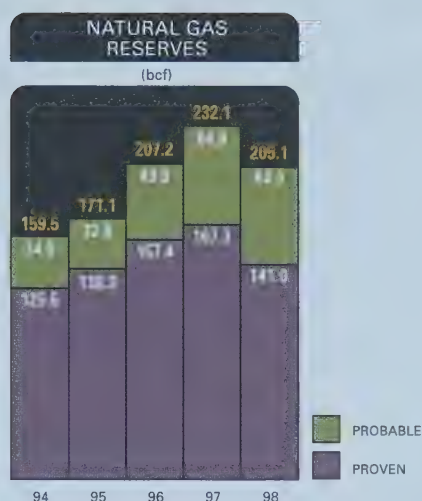


PRODUCTION

Petromet's average production rate in 1998 increased by 22 percent to 5,702 BOE per day compared to 4,691 BOE per day in 1997. Natural gas production increased by 17 percent to 43.7 mmcf per day and contributed 78 percent to oil equivalent production. Production increases were recorded in every quarter of 1998. Fourth quarter production in 1998 was 41 percent higher compared to the same period in 1997. Production from reserve additions supplemented by higher productivity from previously booked proven reserves at Bigstone and Wild River were the main sources of incremental production to the existing base. Petromet's exit rate, as defined by actual production in December 1998, was 6,972 BOE per day corresponding to an increase of 38 percent versus the same period in 1997.

PRODUCTION, BEFORE ROYALTIES

	1998			1997		
	NATURAL GAS MMCF/D	OIL AND NGL BBL/D	OIL EQUIVALENT BOE/D	NATURAL GAS MMCF/D	OIL AND NGL BBL/D	OIL EQUIVALENT BOE/D
Bigstone	26.6	904	3,560	28.7	865	3,732
Wild River	13.2	25	1,346	5.3	34	561
Kakwa	2.7	99	369	0.2	2	24
High Prairie	-	280	280	-	34	34
Other	1.2	21	147	3.0	36	340
Total	43.7	1,329	5,702	37.2	971	4,691



RESERVES

A revision of 6.6 million BOE to proven reserves was recognized in 1998 to ensure that reservoir performance, current economic conditions, and existing technology were realistically assessed within Petromet's reported reserve balances. Revisions were recognized in all of the Company's main producing areas. Proven reserve additions amounted to 5.4 million BOE, which replaced 257 percent of production totalling 2.1 million BOE in 1998. Exploration and development at Wild River and Bigstone, in conjunction with an acquisition at Bigstone, were the most significant sources of proven reserve additions in 1998. The ratio of proven developed producing reserves increased favourably to 85 percent of total proven reserves at year end 1998, compared to 67 percent in 1997. While proven reserves decreased by 16 percent, production increased by 22 percent in 1998 to yield a proven reserve life index of 8.7 years. Probable reserves corresponded to 44 percent of total proven reserves at year end 1998 compared to 39 percent in 1997. The proven plus probable reserve life index was 12.5 years based on 1998 production. Proven reserves consisted of 78 percent from natural gas, 16 percent from NGL, and six percent from oil at year end 1998.

RESERVES, BEFORE ROYALTIES**

	1998			1997†		
	NATURAL GAS BCF	OIL AND NGL MBBLS	OIL EQUIVALENT MBOE	NATURAL GAS BCF	OIL AND NGL MBBLS	OIL EQUIVALENT MBOE
Proven producing	118.9	3,401	15,294	108.2	3,623	14,439
Proven non-producing	2.8	75	353	4.1	121	531
Proven undeveloped	19.3	471	2,404	55.0	930	6,437
Total proven	141.0	3,947	18,051	167.3	4,674	21,407
Probable	64.1	1,489	7,899	64.8	1,853	8,332
Proven plus probable	205.1	5,436	25,950	232.1	6,527	29,739

*Reserves have not been reduced to account for risk.

†Independently assessed at year end by Sproule Associates Limited.

‡Before revisions recognized in 1998.

RESERVE RECONCILIATION

	NATURAL GAS (BCF)			OIL AND NGL (MBBLS)		
	PROVEN	PROBABLE	TOTAL	PROVEN	PROBABLE	TOTAL
December 31, 1995	138.3	32.8	171.1	3,721	935	4,656
Discoveries and extensions	34.7	18.0	52.7	826	181	1,007
Acquisitions	7.0	0.9	7.9	127	35	162
Dispositions	(7.5)	0.0	(7.5)	(225)	0	(225)
Production	(12.1)	0.0	(12.1)	(314)	0	(314)
Revisions of prior estimates	(3.0)	(1.9)	(4.9)	(486)	(241)	(727)
December 31, 1996	157.4	49.8	207.2	3,649	910	4,559
Discoveries and extensions	33.2	19.6	52.8	1,666	1,102	2,768
Acquisitions	6.3	1.4	7.7	225	10	235
Dispositions	(11.5)	(2.3)	(13.8)	(301)	(47)	(348)
Production	(13.6)	0.0	(13.6)	(354)	0	(354)
Revisions of prior estimates	(4.5)	(3.7)	(8.2)	(211)	(122)	(333)
December 31, 1997	167.3	64.8	232.1	4,674	1,853	6,527
Discoveries and extensions	19.9	0.5	20.4	391	(179)	212
Acquisitions	21.2	2.1	23.3	868	195	1,063
Dispositions	0.0	0.0	0.0	0	0	0
Production	(16.0)	0.0	(16.0)	(485)	0	(485)
Revisions of prior estimates	(51.4)	(3.3)	(54.7)	(1,501)	(380)	(1,881)
December 31, 1998	141.0	64.1	205.1	3,947	1,489	5,436

NET PRESENT VALUE BEFORE INCOME TAX**

(\$ millions)	0%	10%	15%	20%
Proven producing	289.1	168.7	142.5	124.5
Proven non-producing	11.5	0.6	0.4	0.3
Proven undeveloped	37.3	16.1	12.2	9.6
Total proven	337.9	185.4	155.1	134.4
Probable	130.8	37.0	25.0	17.7
Proven plus probable	468.7	222.4	180.1	152.1

*Values have not been reduced to account for risk.

+Independently assessed at year end by Sproule Associates Limited.

REFERENCE PRICE FORECASTS*

	OIL		NATURAL GAS	
	WTI, CUSHING, OKLAHOMA \$US/BBL	EDMONTON PAR PRICE 40° API \$/C/BBL	HENRY HUB, LOUISIANA \$/US/MMBTU	ALBERTA REFERENCE PRICE, PLANTGATE \$/C/MMBTU
1999	14.50	21.07	2.10	2.20
2000	16.32	22.82	2.14	2.19
2001	18.21	24.44	2.24	2.24
2002	20.16	26.40	2.33	2.31
Notes	1	1	2	3

1. Escalating at two percent per year thereafter.

2. Increasing gradually to \$US 2.92 per mmbtu by 2011 and escalating by two percent per year thereafter.

3. Increasing gradually to \$2.98 per mmbtu by 2011 and escalating by two percent per year thereafter.

*Reference prices are adjusted to actual prices by incorporating oil and NGL differentials, heating values of natural gas, and fixed price contracts.

CAPITAL EXPENDITURES

Capital expenditures were \$66.4 million in 1998. Of the total amount, 84 percent was spent on exploration, development, and acquisitions and 16 percent was spent on facilities and land. In order to increase cash flow and appraised value, 20 percent of development capital was spent to increase the productivity of previously booked proven reserves. As part of the strategy to diversify investment, 34 percent of total capital expenditures were spent on complementary acquisitions. Expenditures to acquire additional undeveloped land were generally limited to protection acreage or situations where exploration and development plans were imminent. Facilities expenditures were dominated by gathering system extensions to tie in new wells in all core areas, and plant modifications to improve recovery efficiencies and sales capacity at Wild River.

CAPITAL EXPENDITURES

(\$ millions)	1998	1997	1996
Acquisitions, net of dispositions	\$ 22.9	\$ (1.9)	\$ (0.8)
Exploration and development	32.7	31.4	17.5
Facilities	9.2	14.4	3.1
Land	1.6	5.7	3.4
Total capital expenditures	\$ 66.4	\$ 49.6	\$ 23.2

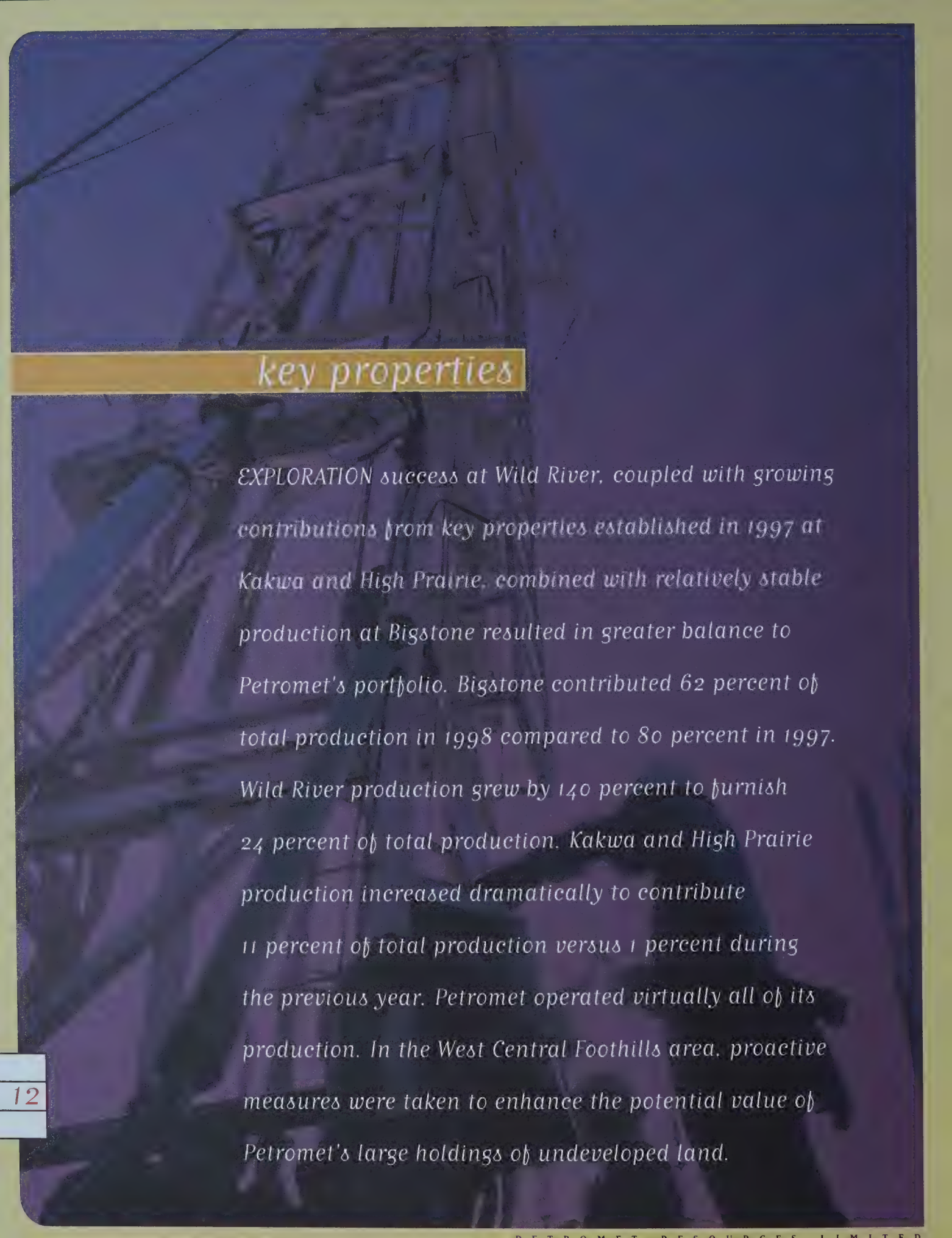
FINDING AND DEVELOPMENT COSTS

Because proven reserve additions in 1998 were less than revisions, the calculation of finding and development costs per BOE resulted in a meaningless negative number. Excluding the impact of reserve revisions, proven finding and development costs in 1998 were \$12.28 per BOE. Petromet began implementing new strategies to target economic value for shareholders after the second quarter of 1998. During the second half of 1998, Petromet incurred capital expenditures of \$41.0 million and added 4.7 million BOE of proven reserves to yield finding and development costs of \$8.71 per BOE. A moderately favourable recycle ratio of 1.46 was achieved based on realizing an operating netback of \$12.75 per BOE during the second half of 1998.

FINDING AND DEVELOPMENT COSTS*

	1998	1997	1996	THREE YEAR	FIVE YEAR
Capital expenditures (\$ millions)	66.4	49.6	23.2	139.2	234.2
Proven reserves added (mmboe)	(1.3)	3.7	3.4	5.8	15.60
Average cost (\$/BOE) (proven)	N/A	13.41	6.82	24.00	15.04
Proven and 50% probable reserves added (mmboe)	(1.5)	5.0	4.2	7.7	16.9
Average cost (\$/BOE) (proven and 50% probable)	N/A	9.92	5.52	18.08	13.85

*Including the impact of reserve revisions.

A dark, atmospheric photograph of an oil rig at night, with lights reflecting on its structure. The image is used as a background for the page.

key properties

EXPLORATION success at Wild River, coupled with growing contributions from key properties established in 1997 at Kakwa and High Prairie, combined with relatively stable production at Bigstone resulted in greater balance to Petromet's portfolio. Bigstone contributed 62 percent of total production in 1998 compared to 80 percent in 1997. Wild River production grew by 140 percent to furnish 24 percent of total production. Kakwa and High Prairie production increased dramatically to contribute 11 percent of total production versus 1 percent during the previous year. Petromet operated virtually all of its production. In the West Central Foothills area, proactive measures were taken to enhance the potential value of Petromet's large holdings of undeveloped land.

HIGH PRAIRIE



ALBERTA

BIGSTONE



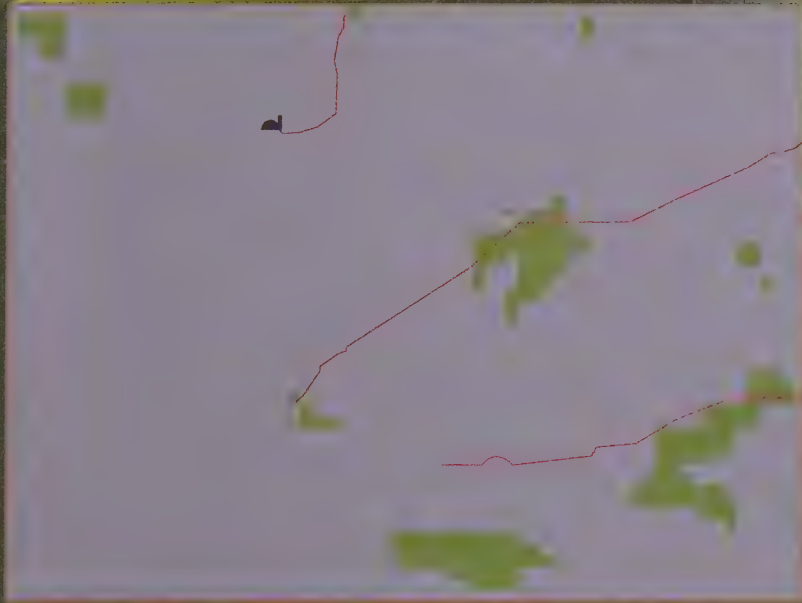
KAKWA



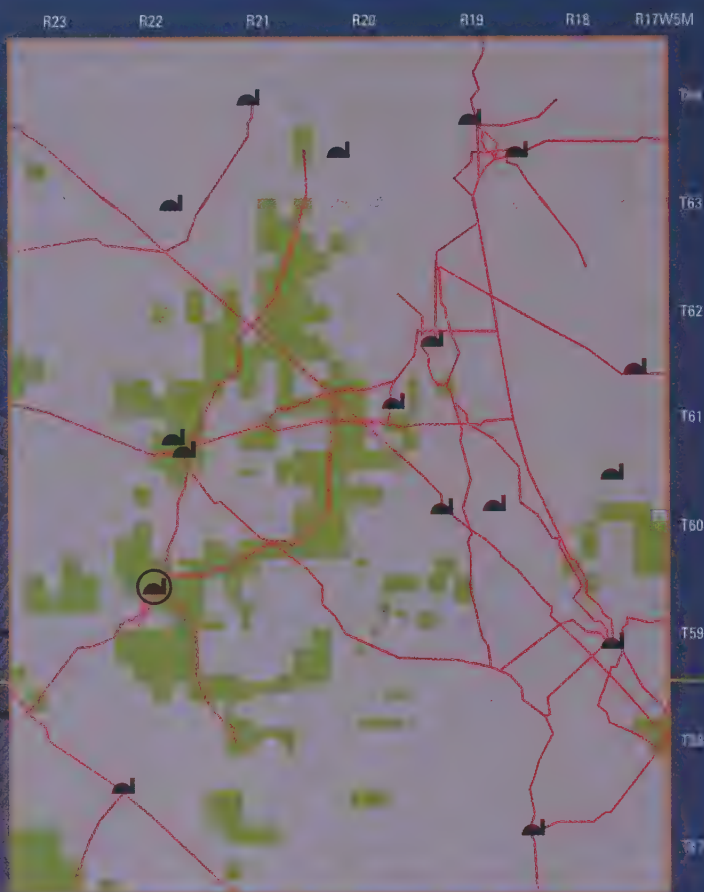
WILD RIVER



WEST CENTRAL FOOTHILLS



PETROMET LAND
NATURAL GAS PIPELINES
GAS PLANT
PETROMET GAS PLANT



bigstone

PROPERTY DESCRIPTION

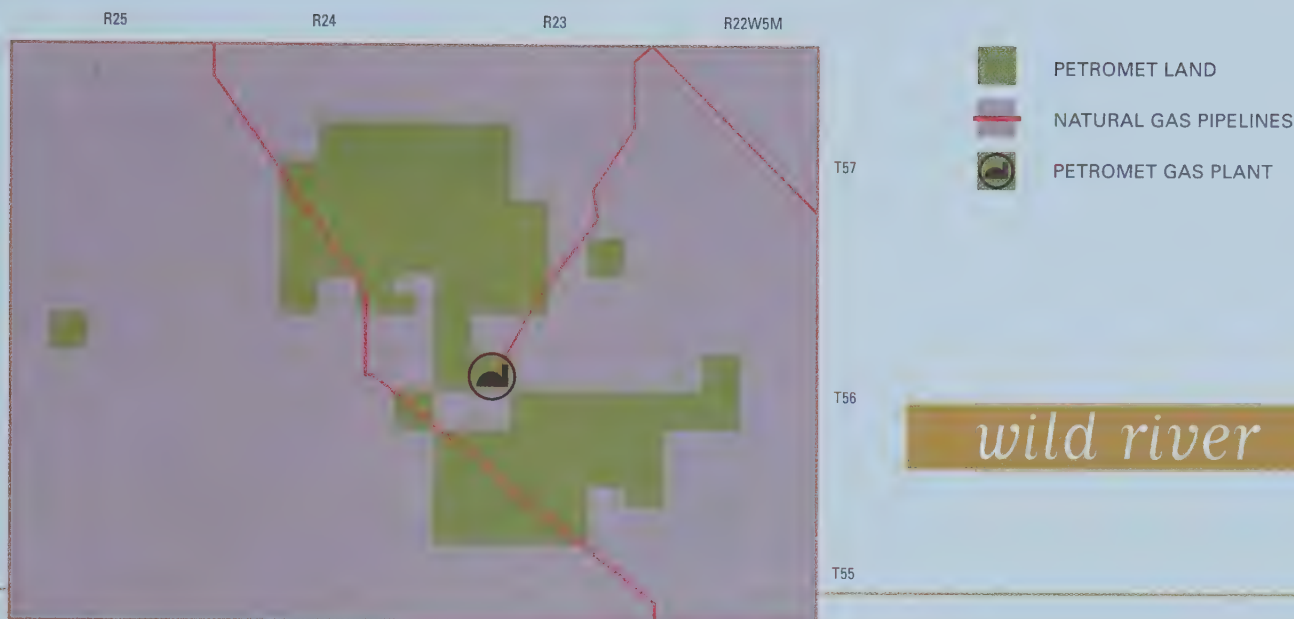
BIGSTONE is the cornerstone of the Company's production base. Petromet is the dominant operator in the area with a 54 percent interest in a 85 mmcf per day gas processing plant and majority interests in 125 miles of gathering systems. Value will be created primarily through more intensive exploitation of existing reservoirs, re-completing secondary and tertiary horizons in existing wells, exploring for medium risk new pool discoveries, processing third party natural gas for fees, and acquiring complementary assets to leverage the Company's cost advantage. Process improvements include a reservoir simulation of the largest producing formation, use of under-balanced horizontal drilling, optimization of infrastructure through a process simulation model, and preemptive use of seismic technology to identify optimal drilling targets.

1998 ACTIVITY

- ⊙ Consolidated operated land and infrastructure through a \$20 million acquisition
- ⊙ Equipped and tied in 12 natural gas wells
- ⊙ Extended the Fir gathering system by six miles
- ⊙ Added five mmcf per day of third party processing

1999 ACTIVITY

- ⊙ Accelerate production through infill drilling of the Dunvegan reservoir
- ⊙ Follow up recent discoveries in the Viking and Gething formations with development drilling
- ⊙ Complete a 13 square mile 3D seismic program
- ⊙ Drill five to ten wells



wild river

PROPERTY DESCRIPTION

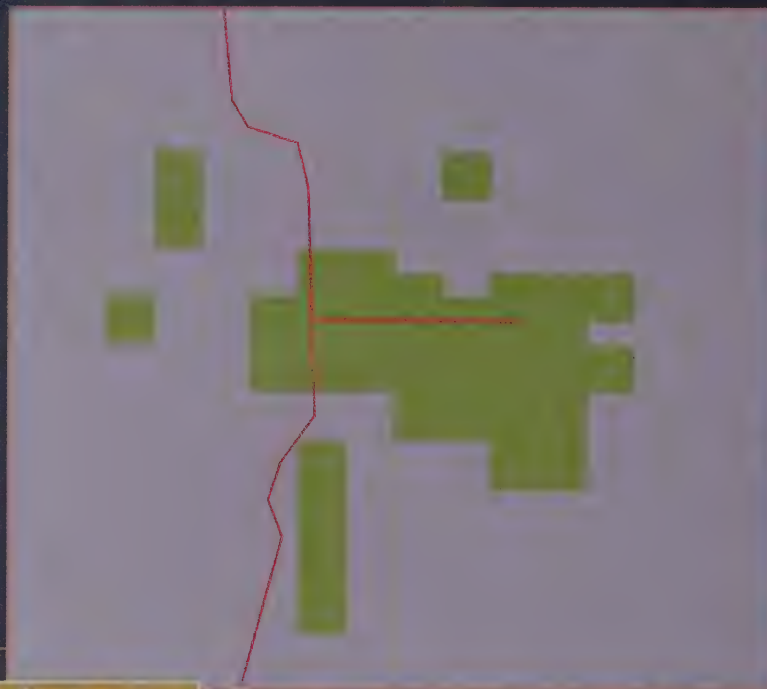
WILD RIVER is the most significant source of recent reserve additions from exploration. Success in 1998 at Wild River has added greater balance to Petromet's production base through dramatic growth from the Leduc formation. Petromet's interpretation of proprietary 3D seismic, understanding of the dual porosity nature of the formation, knowledge of producing characteristics over a sustained period of time, and experience to efficiently drill to depths down to 4,200 metres comprise competitive advantages to sustain growth at Wild River. The economics for deep drilling are enhanced by the availability of a substantial royalty holiday. Production in the area is supplemented by stable long life reserves from several Cretaceous formations. Petromet operates its 75 percent working interest in natural gas processing infrastructure which yields low operating costs at Wild River.

1998 ACTIVITY

- ⊙ Discovered two commercially productive Leduc pinnacle reefs
- ⊙ Equipped and tied in three Leduc reef discoveries including a 1997 discovery
- ⊙ Increased plant capacity by 90 percent to 12 mmcf per day and lowered inlet pressure significantly
- ⊙ Doubled the capacity of the sales gas pipeline to 50 mmcf per day to accommodate high pressure natural gas which bypasses the plant

1999 ACTIVITY

- ⊙ Interpret a new 14 square mile 3D seismic program to identify additional Leduc reef targets
- ⊙ Drill at least two exploration wells for the Leduc formation
- ⊙ Accelerate natural gas production through recompletions in Cretaceous reservoirs



kakwa

PROPERTY DESCRIPTION

KAKWA holds the potential for transformational growth of the Company from exploration. Petromet has assembled significant leverage to the high risk and reward natural gas play in this area where significant reserve discoveries and prolific production rates from the Wabamun formation have been reported by industry competitors. Petromet's strategy is to assess the play at a relatively low working interest while retaining higher working interests in any discoveries and subsequent drilling opportunities. While Petromet does not currently own processing infrastructure in the area, proving significant reserves is expected to provide processing options at reasonably favourable operating costs under new proprietary or leased facilities.

1993 A. E. HAYES

- ② Earned 6,387 net acres of undeveloped land through the fulfillment of capital commitments
- ② Obtained 112 miles of 2D seismic and drilled one successful natural gas well
- ② Secured an option on 23,480 net acres of undeveloped land

1990 ACTIVITIES

- ② Complete and test a 4,100 metre Wabamun well at 16 percent before payout and 30 percent after payout
- ② Interpret a new 14-square mile 3D seismic program to identify optimal drilling locations on lands held under option
- ② Drill one or more wells to test the Wabamun formation on lands held under option at 100 percent before payout and 60 percent after payout
- ② Obtain significant additional 2D seismic data to identify more Wabamun prospects



-  PETROMET LAND
-  OIL PIPELINE
-  PETROMET OIL BATTERY

high prairie

PROPERTY DESCRIPTION

HIGH PRAIRIE contributes virtually all of Petromet's oil production. Petromet's current strategy is to optimize the profitability of existing operations while retaining the option to pursue growth should that be justified by improving economics for oil exploration. Production has stabilized and operating costs have been reduced such that the property provides reasonable operating margins and cash flow to fund capital expenditures on natural gas opportunities in other areas.

1998 ACTIVITY

- ⊙ Drilled four Gilwood wells
- ⊙ Constructed a 450 bbl per day satellite facility
- ⊙ Tied four wells into the satellite facility
- ⊙ Acquired working interests from the largest partner
- ⊙ Captured third party processing through the central battery
- ⊙ Reduced operating costs by 40 percent to \$3.50 per bbl

1999 ACTIVITY

- ⊙ Minimize decline through production engineering
- ⊙ Defer drilling of seismically identified locations until oil prices recover

PETROMET LAND
NATURAL GAS PIPELINE
GAS PLANT



west central foothills

PROPERTY DESCRIPTION

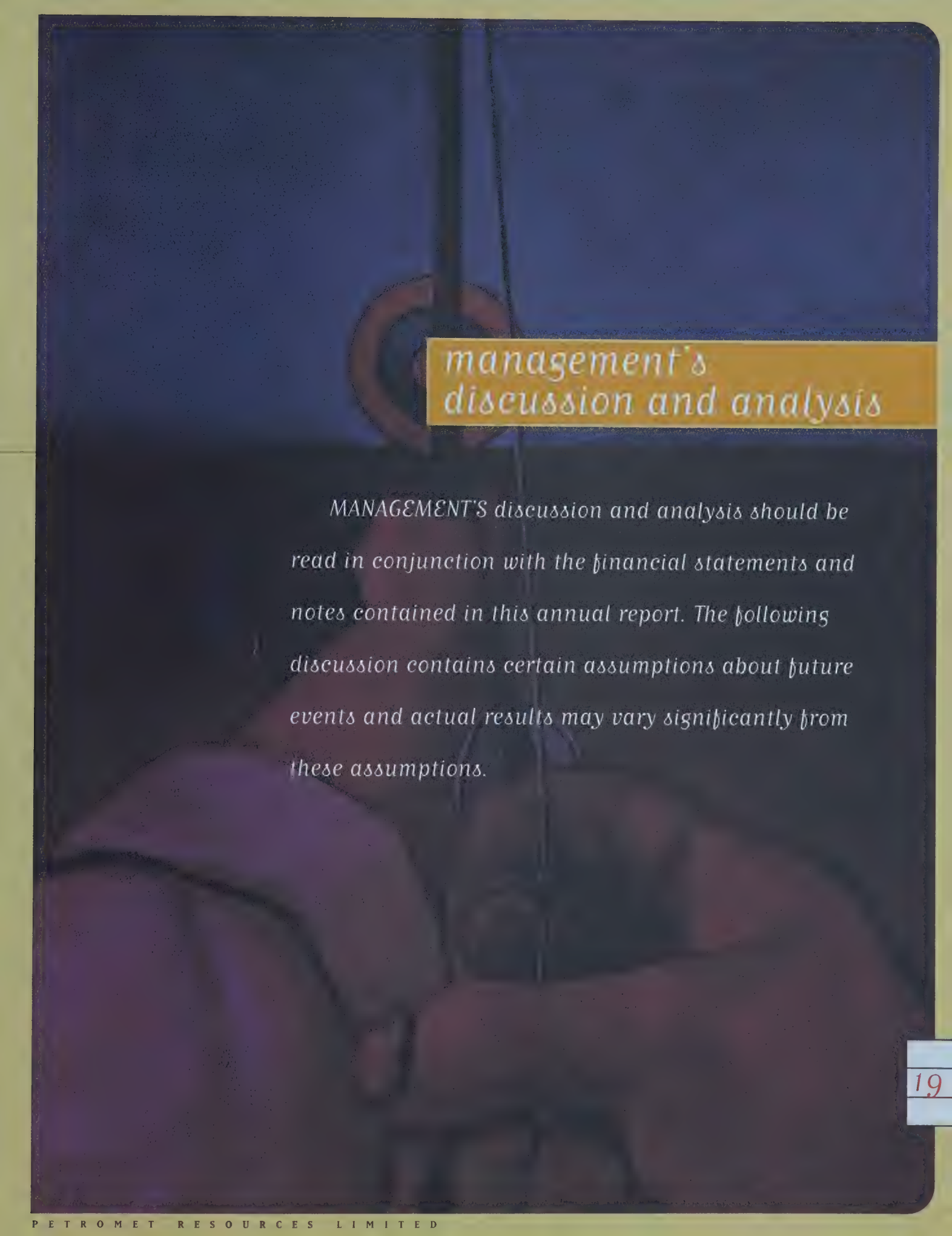
WEST CENTRAL FOOTHILLS is the largest source of emerging exploration opportunities for Petromet. A large undeveloped land position consisting of 143,560 net acres at an average working interest of 95 percent provides significant potential within this underexplored gas prone area. Petromet's strategy is to accelerate exploration by attracting risk capital and supplemental technical resources through joint venture partnerships while retaining options to participate in drilling under favourable terms. Lands have been prioritized according to geological prospectivity and remaining tenure.

At Grande Cache, where Petromet holds 32,480 net acres of undeveloped land, 55 miles of new 2D seismic was acquired late in 1998

at no cost to the Company. Additional seismic will be acquired in 1999 to resolve a drilling location for late in the year. The area is prospective for natural gas in faulted Triassic and Mississippian formations at depths between 2,000 and 4,200 metres. Third party infrastructure is now accessible in the area since the adjacent Findley field commenced production early in 1999.

At Huckleberry, where Petromet holds 34,240 net acres of undeveloped land, the Company and an industry partner acquired 73 miles of new 2D seismic data which is currently being interpreted for natural gas targets in multiple formations down to 3,200 metres in depth.

At Narraway, the Company holds 13,480 net acres of undeveloped land on which an industry partner has committed to provide 22 miles of new 2D seismic data to identify natural gas potential in multi-zone faulted anticlines at depths down to 4,000 metres.



management's discussion and analysis

MANAGEMENT'S discussion and analysis should be read in conjunction with the financial statements and notes contained in this annual report. The following discussion contains certain assumptions about future events and actual results may vary significantly from these assumptions.

OVERVIEW

The tables below provide summaries of Petromet's operations during the past three years.

PRODUCTION

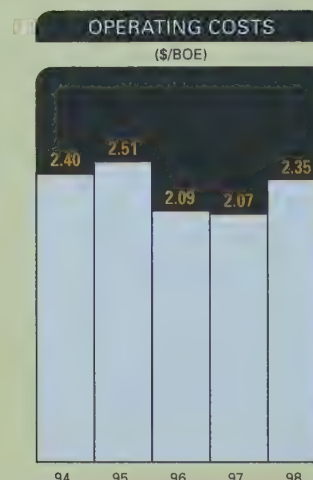
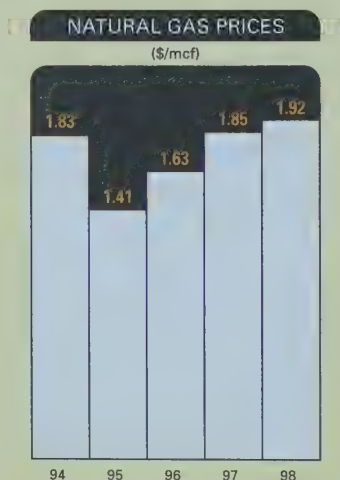
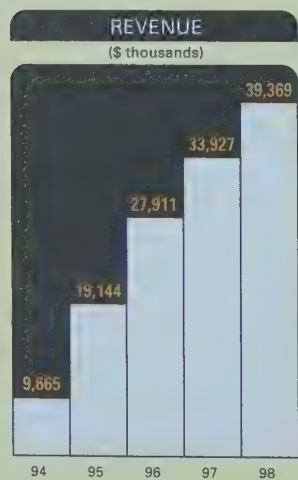
	1998	1997	1996
Natural gas (mmcf/d)	43.7	37.2	33.1
Oil and NGL (bbl/d)	1,329	971	859
Oil equivalent (BOE/d)	5,702	4,691	4,169

AVERAGE PRICES

	1998	1997	1996
Natural gas (\$/mcf)	1.92	1.85	1.63
Oil and NGL (\$/bbl)	16.21	23.42	24.25
Other income (\$/BOE)	0.42	0.29	0.36

\$ PER BOE

	1998	1997	1996
Petroleum and natural gas revenue	18.92	19.82	18.30
Royalties	3.32	4.10	3.75
Alberta Royalty Tax Credit	0.67	0.71	0.96
Operating costs	2.35	2.07	2.09
Field netback	13.92	14.36	13.42
General and administrative costs	1.17	0.66	0.90
Current taxes	0.21	0.18	0.17
Operating netback	12.54	13.52	12.35
Cash interest	2.23	1.50	1.90
Cash flow from operations	10.31	12.02	10.45
Depletion and depreciation	8.22	6.96	6.23
Deferred taxes	0.90	2.31	2.47
Non-cash interest	0.14	0.16	0.18
Net income from operations	1.05	2.59	1.57
Gain on sale of investments	-	-	2.45
Net income	1.05	2.59	4.02



\$ THOUSANDS

	1998	1997	1996
Petroleum and natural gas revenue	39,369	33,927	27,911
Royalties	6,906	7,017	5,727
Alberta Royalty Tax Credit	1,387	1,215	1,469
Operating costs	4,894	3,548	3,191
Field netback	28,956	24,577	20,462
General and administrative costs	2,430	1,127	1,373
Current taxes	433	315	261
Operating netback	26,093	23,135	18,828
Cash interest	4,631	2,574	2,898
Cash flow from operations	21,462	20,561	15,930
Depletion and depreciation	17,096	11,924	9,496
Deferred taxes	1,881	3,960	3,774
Non-cash interest	280	280	280
Net income from operations	2,205	4,397	2,380
Gain on sale of investments	-	-	3,738
Net income	2,205	4,397	6,118

MARGINS (%)

	1998	1997	1996
Petroleum and natural gas revenue	100.0	100.0	100.0
Royalties	17.5	20.7	20.5
Alberta Royalty Tax Credit	3.5	3.6	5.3
Operating costs	12.4	10.5	11.4
Field netback	73.6	72.4	73.3
General and administrative costs	6.2	3.3	4.9
Current taxes	1.1	0.9	0.9
Operating netback	66.3	68.2	67.5
Cash interest	11.8	7.6	10.4
Cash flow from operations	54.5	60.6	57.1
Depletion and depreciation	43.4	35.1	34.0
Deferred taxes	4.8	11.7	13.5
Non-cash interest	0.7	0.8	1.0
Net income from operations	5.6	13.0	8.5
Gain on sale of investments	0.0	0.0	13.4
Net income	5.6	13.0	21.9

REVENUE

Petroleum and natural gas revenue increased by 16 percent to \$39.4 million in 1998. Contributing to higher revenue in 1998 were production volumes which increased by 22 percent to 5,702 BOE per day. The contribution of natural gas to total revenue increased by four percent in 1998. Revenue growth was dampened by the impact of product prices which declined by five percent to \$18.92 per BOE in 1998. Natural gas prices increased by four percent to \$1.92 per mcf but were more than offset on a volume weighted basis by prices for oil and NGL which declined by 31 percent to \$16.21 per bbl. In 1999, natural gas prices are expected to increase due to the contribution of fixed price contracts on a majority of forecasted natural gas production at contracted

prices which are 20 percent higher compared to the average realization in 1998. Natural gas prices may also benefit from tight supplies due to reduced capital spending by industry, and from shrinking basis differentials caused by a surplus of export pipeline capacity in western Canada.

REVENUE

(\$ THOUSANDS)	1998		1997		1996	
	REVENUE	%	REVENUE	%	REVENUE	%
Natural gas sales	\$ 30,639	78	\$ 25,135	74	\$ 19,737	71
NGL sales	5,527	14	7,480	22	7,392	26
Oil sales	2,335	6	822	3	230	1
Other	868	2	490	1	552	2
Petroleum and natural gas revenue	\$ 39,369	100	\$ 33,927	100	\$ 27,911	100

Production of natural gas increased 17 percent to 43.7 mmcf per day from 37.2 mmcf per day in the prior year. Increased gas production, from new wells at Wild River and the full year impact of production from Kakwa, contributed an additional \$4.4 million in revenue. The average price received for natural gas, including a loss realized on forward foreign exchange contracts of \$0.02 per mcf, increased slightly to \$1.92 per mcf from \$1.85 per mcf in 1997. This four percent increase in natural gas pricing increased revenue by \$1.1 million.

Production volumes of oil and NGL increased by 37 percent to average 1,329 bbls per day in 1998 from 971 bbls per day in 1997. Oil production increased from 87 bbls per day in 1997 to 342 bbls per day in 1998. Increased oil production was entirely attributable to the High Prairie area. Production of NGL increased from 885 bbls per day in 1997 to 987 bbls per day in 1998. The majority of the increased NGL production resulted from the Kakwa area which was added late in 1997 and therefore had only a minimal impact on prior year production. Although the increased production of oil and NGL increased gross revenue by \$3.1 million in 1998, this increase was more than offset by declining oil and NGL prices.

Oil and NGL prices received fell to \$16.21 per bbl in 1998 from \$23.42 per bbl in the prior year, a decrease of 31 percent. The price for crude oil declined due to an unfavourable worldwide imbalance between supply and demand. NGL prices declined commensurately, aggravated by lower premiums for condensate due to much weaker demand for its use as a diluent for heavy oil transportation in western Canada. The Company's average oil price received fell from \$26.10 per bbl in 1997 to \$18.82 per bbl in 1998. The price received for NGL production is largely influenced by the price of crude oil and accordingly average prices received fell to \$15.38 per bbl in 1998 from \$23.16 in the prior year. Price declines on oil and NGL resulted in decreased revenue of \$3.5 million.

Other revenue represents capital recoveries from third party processing through Company owned facilities. Recoveries increased at both the Bigstone and Wild River facilities in 1998 as additional third party volumes were connected.

RECONCILIATION OF REVENUE INCREASE (\$ THOUSANDS)

1997 Revenue	\$ 33,927
Increased volumes of natural gas	4,422
Increased volumes of oil and NGL	3,056
Increased price of natural gas	1,082
Decreased price of oil and NGL	(3,496)
Increased other income	378
1998 Revenue	\$ 39,369

ROYALTIES

Royalties (net of ARTC), declined 22 percent to \$2.65 per BOE in 1998 from \$3.39 per BOE in 1997. This decline was caused by lower royalties on oil and NGL, in accordance with reduced pricing, and also by the crown royalty holiday applicable to new deep gas production at Wild River. ARTC receipts for the 1998 production year were \$1.4 million (versus \$1.2 million in 1997); however, on a production unit basis, ARTC received declined from \$0.71 per BOE in 1997 to \$0.67 per BOE in 1998. In 1999, the Company's royalty rate is expected to stay relatively constant as higher prices expected for natural gas are likely to be partially offset by increased royalty free production at Wild River.

OPERATING EXPENSES

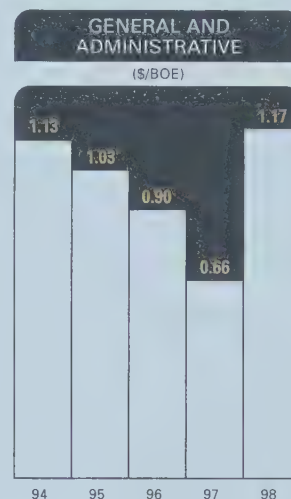
Operating expenses increased on a production unit basis from \$2.07 per BOE in 1997 to \$2.35 per BOE in the current year. Operating costs are presented net of the operating portion of recoveries realized from third party processing in Company owned facilities. Operating costs increased sharply during the first half of 1998, to an average of \$2.70 per BOE, due to increased water hauling in both the Peace River and High Prairie areas. Higher operating costs were also incurred as a result of start up costs in both the Kakwa and Wild River areas.

Unit operating costs declined throughout the second half of the year as a result of suspending Peace River operations, tying in production at High Prairie to eliminate water hauling costs, and reducing start up costs in all areas. Significant volumes of low operating cost production were added at Wild River and Bigstone.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses, before overhead recovered by the Company as operator, increased to \$1.90 per BOE in 1998 from \$1.55 per BOE in 1997. General and administrative expenses increased due to increasing activity levels as well as specific items attributable to changes in management personnel. The non-recurring items amounted to approximately \$0.20 per BOE in the 1998 year. Office personnel increased from 22 people at the end of the previous year to 29 people at the end of 1998.

Overhead recovered by the Company from operating, drilling and construction activities was relatively unchanged in absolute terms but decreased on a production unit basis, reflecting the increased production in 1998. Net general and administrative expenses were \$1.17 per BOE in 1998 versus \$0.66 per BOE in 1997. General and administrative expenses per BOE are expected to be significantly lower during 1999.



GENERAL AND ADMINISTRATIVE EXPENSES

(\$ THOUSANDS)	1998	1997	1996
Gross expenses	\$ 3,957	\$ 2,646	\$ 2,406
Operator recoveries	(1,527)	(1,519)	(1,033)
Net expenses	\$ 2,430	\$ 1,127	\$ 1,373
Average cost per BOE			
Gross expenses	\$ 1.90	\$ 1.55	\$ 1.58
Operator recoveries	(0.73)	(0.89)	(0.68)
Net expenses	\$ 1.17	\$ 0.66	\$ 0.90
Employees as at December 31			
Head office	29	22	19
Field	13	12	10
Total	42	34	29

INTEREST

Interest expense increased to \$4.9 million in 1998 from \$2.9 million in 1997 reflecting the higher average debt level used to finance the 1998 capital expenditure program. On a production unit basis, interest expense increased 42 percent to \$2.36 per BOE in 1998. At year end, the Company's debt consisted of approximately 72 percent in banking facilities and 28 percent in convertible debentures. The banking facilities are utilized primarily through bankers' acceptances and are subject to floating interest rates. The convertible debentures are due March 31, 2004 and bear interest at a fixed rate of 6.5 percent per annum on the issued principal value of \$25 million.

The convertible debentures are accounted for in accordance with the recommendations for presentation and disclosure of financial instruments. This presentation results in an equity component, reflected in the financial statements as paid-in capital, which is amortized as interest expense over the term of the debentures. Annual amortization of the equity component results in non-cash interest of \$280,000.

CURRENT TAXES

Current taxes are comprised entirely of the federal large corporation tax on capital as the Company is not currently taxable on income and does not have any operations outside of Alberta. The large corporation tax paid by the Company increased by 37 percent in 1998 resulting in \$0.21 per BOE (versus \$0.18 per BOE in 1997).

DEPLETION AND DEPRECIATION

Depletion and depreciation is determined on the unit-of-production method based on total proven reserves with natural gas converted to oil equivalence using six thousand cubic feet per barrel. This conversion factor approximates the relative energy value and is commonly used in depletion calculations. Depletion and depreciation on a production unit basis increased to \$8.22 per BOE in 1998 from \$6.96 per BOE in the prior year. Depletion on a production unit basis increased due to a higher depletable base combined with the net reduction of proven reserves. Depletion per BOE is expected to increase significantly in 1999 reflecting the full year impact of the higher depletion costs per BOE incorporated in the fourth quarter of 1998.

Depreciation on gas plant facilities is calculated on a straight line basis over the life of the facilities. The provision for future abandonment and site restoration remained relatively consistent at \$0.32 per BOE in 1998. The provision for future abandonment and site restoration is determined by management in consultation with the Company's engineers and is based on prevailing regulations, costs, technology and industry standards. The total future liability is estimated at \$10.2 million at December 31, 1998 (1997 - \$7.9 million). Current expenditures for abandonment and site restoration of producing properties were \$58,000 (1997 - \$54,000).

DEPLETION AND DEPRECIATION

(\$ PER BOE)	1998	1997	1996
Depletion	\$ 7.28	\$ 6.06	\$ 5.21
Depreciation	0.62	0.61	0.71
Site restoration provision	0.32	0.29	0.31
	\$ 8.22	\$ 6.96	\$ 6.23

DEFERRED INCOME TAXES

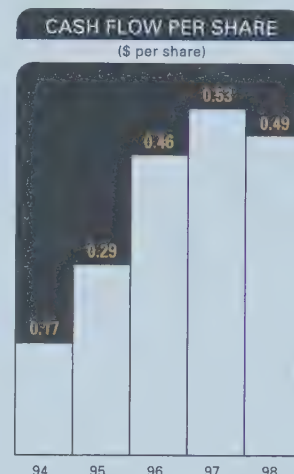
The provision for deferred income taxes in 1998 was \$1.9 million representing an effective rate of 41.6 percent versus an effective rate of 45.7 percent in 1997. The effective tax rate can vary substantially from year to year depending on the relative contribution of income sources, incentive allowances and non-deductible expenses. The Company had approximately \$159 million of tax pools remaining at December 31, 1998 and is not likely to be taxable on an current basis for several years.

NET INCOME

Net income decreased by 50 percent to \$2.2 million, primarily as a result of lower prices for oil and NGL production, increased depletion and depreciation charges commensurate with the reserve revision, and increased interest costs from higher levels of debt.

SUMMARY PER SHARE

Daily production per share increased by seven percent as production gains were financed primarily through the use of debt and cash flow from operations. Cash flow from operations increased four percent to \$21.5 million in 1998 compared to \$20.6 million in 1997. Cash flow per share decreased to \$0.49 per share for 1998 versus \$0.53 per share in 1997 reflecting an increase in the weighted average number of shares outstanding. The weighted average number of shares outstanding in 1998 increased 13 percent over the comparable period, primarily reflecting the full year impact of the issue of approximately 5.7 million shares late in the third quarter of 1997.



	1998	1997	1996
Weighted average shares outstanding (millions)	43.6	38.5	34.3
Production (daily BOE per million shares)	130.8	121.8	121.5

\$ PER SHARE

	1998	1997	1996
Petroleum and natural gas revenue	0.90	0.88	0.81
Field netback	0.66	0.64	0.60
Operating netback	0.60	0.60	0.55
Cash flow from operations	0.49	0.53	0.46
Net income from operations	0.05	0.11	0.07
Net income	0.05	0.11	0.18

LIQUIDITY AND CAPITAL RESOURCES

Compared to 1997, long-term debt net of working capital increased by 11 percent relative to total capitalization at cost in 1998. The Company's forecast of improving cash margins, use of fixed price contracts, and anticipated increases in production provide support for the increased debt level.

CAPITALIZATION

(\$ THOUSANDS)	AT COST		AT MARKET*	
	AMOUNT	%	AMOUNT	%
Common share equity	\$ 107,630	53	\$ 133,676	59
Long-term debt, net of working capital	83,833	41	82,303	36
Deferred taxes	8,623	4	8,623	4
Other liabilities	2,262	2	2,262	1
Total	\$ 202,348	100	\$ 226,864	100

*The closing price on December 31, 1998 was \$2.95 per common share, and \$88.00 per convertible debenture.

Capital expenditures in 1998 of \$66.4 million were financed through a combination of cash flow, proceeds from share issues, and increased utilization of banking facilities. The 1998 budget was increased to allow for the acquisition of additional interests at Bigstone. This transaction, which was effective July 1, 1998, represented approximately 30 percent of current year expenditures and was financed entirely through debt facilities.

Common shares issued during 1998 included 1,025,522 resulting from the exercise of stock options and 1,567,113 flow-through common shares issued in private placements. These issues brought the total number of outstanding common shares to 45,314,156 at year end. In 1997, the Company retroactively changed its accounting policy for flow-through shares to adjust for the estimated cost of renounced tax deductions. Management believes this policy is more comparable to similar sized companies. The effect of this change in policy is discussed further in the Notes to the Financial Statements.

At December 31, 1998 the Company had working capital of \$0.7 million versus a deficiency of \$3.0 million at the end of 1997. Combined bank debt and working capital amounted to \$60.3 million at year end. The current bank facilities are \$75 million subject to the 1999 review of current activities and reserve values. The 1999 capital budget has been approved at \$35 million. The Board of Directors reviews the capital budget throughout the year and will amend it as projects progress and additional opportunities arise. The Company's exploration and development program is not influenced by any contractual commitments and no such material commitments for capital expenditures exist at December 31, 1998.

BUSINESS RISKS

Exploration, development and production of oil and natural gas involve many risks which even a combination of experience, knowledge and careful evaluation may not be sufficient to overcome. These risks are mitigated by employing highly skilled staff, focusing exploration efforts in areas in which Petromet has existing knowledge and expertise or access to such expertise, using up-to-date technology methods, and controlling costs to maximize margins. In addition, the Company's strategy of maintaining controlling interests in owned and operated facilities ensures that it will continue to be a low cost producer. The Company has a comprehensive insurance program designed to mitigate risks and protect against significant loss; however, it is not fully insured against all these risks, nor are all such risks insurable. Insurance for liability, property, and business interruption is considered adequate and is consistent with common industry practice.

Financial risks include exposure to fluctuation in commodity prices, currency exchange rates, and interest rates. To mitigate commodity price risk, the Company maintains direct marketing control over its production and maintains a diversified portfolio to reduce exposure to short-term fluctuations. The Company enters into physical contracts for the sale of natural gas at fixed prices and terms and currently has fixed pricing arrangements in place as follows:

- ⊙ \$2.30 per mcf on 31.8 mmcf per day of production in 1999
- ⊙ \$2.55 per mcf on 14.4 mmcf per day of production in 2000, and
- ⊙ \$2.60 per mcf on 7.4 mmcf per day of production in 2001.

Purchasers of the Company's production are subject to internal credit review and the Company is not aware of any of its sales being subject to undue credit risk.

To reduce exposure to currency rate fluctuations, the Company has fixed the exchange rate on the portion of 1999 production which has fixed pricing in US dollars. At year end the cost to the Company to settle these contracts is estimated at \$20,000. Although not currently utilized, the Company may institute financial hedging techniques for interest rates and commodity prices. If utilized, such transactions would be subject to certain limits on term and amount established by the Board of Directors.

The oil and gas industry, while subject to stringent environmental regulatory control, is undergoing significant change with increased responsibility of self-regulation and compliance. In view of this situation, Petromet has taken a proactive approach to improving the environmental performance of the Company by the development of an Environmental Management System. This Environmental Management System sets out the corporate environmental philosophy, objective, risk assessment, organizational structure, policies and procedures and auditing functions necessary in providing an effective comprehensive method of controlling all environmentally related issues. The system focuses on prevention and mitigation, rather than reaction and response techniques after environmental incidents have occurred. The system also incorporates existing safety policies and emergency response plans, as a complete package, to ensure the protection of the environment, the safety of

the general public and all personnel. Petromet retains the services of an environmental consulting firm to provide advice and current regulatory information, to prepare environmental assessments for facilities, pipelines and sites prior to commencement of a project, and to perform regular audits of operated facilities. The results of the regular audits are submitted to the Directors at each regular Board meeting.

OUTLOOK

Petromet's cash flow would change by approximately \$1.7 million for a \$0.10 per mcf change in natural gas prices. The Company has fixed a majority of its anticipated natural gas production in 1999 resulting in reduced exposure to market changes in natural gas prices. A change of 10 mmcf per day of natural gas production would impact cash flow by approximately \$6.4 million. Petromet's exposure to changes in prices for oil and NGL is relatively low compared to natural gas prices because of the Company's high weighting to natural gas production in its forecast.

CASH FLOW SENSITIVITIES

APPROXIMATE IMPACT IN 1999	CASH FLOW \$ MILLIONS	\$/SHARE
Natural gas		
Change of \$0.10 per mcf in average price	1.7	0.04
Change of 10 mmcf per day of production	6.4	0.14
Oil and NGL		
Change of \$1.00 per bbl in average price	0.4	0.01
Change of 100 bbls per day of production	0.3	0.01

YEAR 2000 READINESS DISCLOSURE STATEMENT

The Year 2000 problem puts all date sensitive systems at risk of a malfunction during the transition from 1999 to 2000 and on other critical dates. Companies may also be adversely affected by the failure of key suppliers and business associates to be Year 2000 ready. Because of the uncertainties surrounding the Year 2000 problem, no business can guarantee that it will be completely Year 2000 ready.

To prepare for the Year 2000, Petromet has assembled a Year 2000 Project Team, comprised of personnel from operations, accounting and information technology, and overseen by the Vice President of Operations. It reports weekly to a committee of senior management, and the Directors are updated at each regular Board meeting. Awareness of Petromet's preparations to become Year 2000 ready extends to all employees, who have access to information about the Year 2000 Program.

Petromet's Year 2000 Program is comprised of the following main elements:

Process Control:	To prepare the Company's field operations and facilities, an outside consultant was retained to assess Year 2000 readiness with a three phase project including: (1) taking inventory of computer software, firmware, hardware and devices with embedded systems or other date sensitive functions, and assessing inventory by risk of failure, (2) assessing Year 2000 readiness of inventory by inspection, testing, investigation or validation, and (3) remediation by implementing solutions as deemed necessary, followed by additional testing.
Information Technology:	To prepare the Company's technology (other than process control), including accounting software, personal computers, telecommunication systems, seismic interpretation software involves a two phase project including: (1) taking inventory of computer software, firmware, hardware and devices with embedded systems or other date sensitive functions, and assessing inventory by risk of failure, (2) testing procedure including (a) development of testing strategy, (b) development and execution of test plan, (c) documenting test results; and (d) Year 2000 signoff.

Stakeholder Readiness:	Communication with business partners (including joint venture operators, pipeline transporters and processors) and suppliers of goods and services (including public utilities and field operation suppliers), and to assess the risk to the Company of their potential non-Year 2000 readiness.
Contingency Planning:	Ongoing planning for contingencies that may arise, as identified by information obtained by the Process Control, Information Technology and Stakeholder Readiness projects, and such contingency plans will include, but not be limited to, the use of existing plans, such as emergency response plans, safety procedures, environmental policies and procedures.
Change Control:	Procedure to reduce the risk of non-Year 2000 ready changes being introduced into the Company after remediation efforts in both the field and office have been implemented.
Stakeholder Communication:	Provision of information as to the Company's Year 2000 readiness to stakeholders dependent on Petromet, as deemed necessary.
Legal Review:	Legal counsel has been retained to assist in understanding and minimizing the Company's exposure to liability and to assist in preparing the Company in the event it must recover losses caused by external parties.

COST

Petromet has not incurred material costs to date in respect of its Year 2000 Program, nor does it anticipate its future costs will be material. Costs in relation to the Year 2000 Program will be expensed or capitalized, depending on their nature.

To the end of January, 1999, costs included in general and administrative expenses in relation to the Year 2000 Program were approximately \$51,000. The total estimated expenses in respect of the Year 2000 Program are estimated to be approximately \$270,000. The total estimated capital costs in respect of the Year 2000 Program are estimated to be approximately \$230,000.

Petromet's total estimated costs in respect of the Year 2000 Program are less than two percent of the Company's estimated 1999 capital expenditures. These estimated costs do not include the Company's potential share of Year 2000 related costs that may be incurred by joint ventures not operated by the Company. Funds in respect of the Year 2000 Program costs are being obtained from internally generated cash flow. The Company believes its estimate of costs for the Year 2000 Program to be reasonable, however, there can be no assurance that the actual cost of implementing the Year 2000 Program will not differ materially from the estimate.

YEAR 2000 PROJECT STATUS

The Process Control and Information Technology projects are substantially underway with estimated completion dates of June, 1999. The Stakeholder Readiness project has commenced and is targeted for substantial completion by June of 1999, with further assessment of stakeholder's readiness as deemed necessary. Contingency Planning is occurring in the first half of 1999, with ongoing revisions as deemed necessary. The Change Control Project and Legal Review will continue throughout 1999 and into the Year 2000.

SUMMARY

Petromet's Year 2000 Program is intended to prepare Petromet for the Year 2000 and reduce its exposure to the risks inherent to the Year 2000 problem. However, Petromet cannot ensure the Year 2000 readiness of its stakeholders. They are not obligated to respond to inquiries and the Company cannot verify the accuracy of information disclosed. Due to the scope and nature of the problem, neither Petromet or its stakeholders can make any guarantees as to Year 2000 readiness.

The impact of a Year 2000 problem on Petromet could range from a minor error to a major failure affecting the Company's ability to carry on uninterrupted business. Petromet depends on public utilities and on third parties, such as pipeline transporters, failure of which could result in a business interruption to Petromet. Contingency planning and remediation efforts are aimed at reducing exposure to these risks.

To date, the Company is not aware of any significant concerns in the areas of safety, environmental or business interruption in respect of the Year 2000 problem. The Year 2000 Program will continue into the Year 2000, to assess and remediate any problems identified after January 1, 2000.

SUPPLEMENTARY INFORMATION

NET ASSET VALUE

(\$ MILLIONS, EXCEPT PER SHARE)	DISCOUNTED AT	
	10%	15%
Net present value of reserves, before income taxes*+	203.9	167.6
Value of undeveloped land *	28.5	28.5
Working capital	0.7	0.7
Long-term debt	(84.5)	(84.5)
Net asset value **	148.6	112.3
Net asset value per share ++	\$3.28	\$2.48

* Based on independent appraisal at December 31, 1998.

** Excludes the value of proprietary seismic, surplus capacity in proprietary infrastructure, and other assets.

+ Probable reserve value has been reduced by 50 percent to account for risk.

++ 45,314,156 shares outstanding at December 31, 1998.

QUARTERLY SUMMARIES

	1998				1997			
	MAR 31	JUNE 30	SEP 30	DEC 31	MAR 31	JUNE 30	SEP 30	DEC 31
FINANCIAL								
(\$ millions, except per share)								
Revenue	8.5	8.1	9.8	13.0	9.4	7.8	7.9	8.8
Cash flow	5.3	3.9	4.9	7.3	6.2	4.9	4.5	5.0
Cash flow per share	0.12	0.09	0.11	0.17	0.17	0.13	0.12	0.11
Net income	1.3	0.2	0.3	0.3	2.1	1.3	0.9	0.1
Net income per share	0.03	0.01	0.01	0.01	0.06	0.03	0.02	0.00
Capital expenditures	16.2	9.2	31.4	9.7	13.4	8.3	9.3	18.6
OPERATING								
Production								
Natural gas (mmcf/d)	36.2	40.1	46.8	51.6	38.3	37.3	36.3	36.8
Oil and NGL (bbls/d)	1,187	1,102	1,472	1,548	940	947	932	1,065
Average prices								
Natural gas (\$/mcf)	1.91	1.70	1.75	2.24	2.05	1.72	1.77	1.87
Oil and NGL (\$/bbl)	19.78	16.15	15.04	14.69	26.53	21.59	21.27	24.23



MANAGEMENT'S REPORT

The accompanying financial statements and all information in the annual report are the responsibility of management. The financial statements have been prepared utilizing management's best estimates and judgements. In the opinion of management, these financial statements have been prepared within reasonable limits of materiality and are in accordance with Canadian generally accepted accounting principles.

Petromet maintains systems of internal controls to provide reasonable assurance that assets are safeguarded and to facilitate the preparation of relevant and reliable financial information on a timely basis.

External auditors, appointed by the shareholders, have examined the financial statements. The Audit Committee, consisting of a majority of non-management directors, has reviewed the financial statements with management and the external auditors. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

J.J. Nieuwenburg
President & Chief Executive Officer

S. A. Supple
Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Petromet Resources Limited

We have audited the balance sheets of Petromet Resources Limited as at December 31, 1998 and 1997 and the statements of income, retained earnings and changes in financial position for each of the years in the three year period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1998 and 1997, the results of its operations and the changes in its financial position for each of the years in the three year period ended December 31, 1998 in accordance with generally accepted accounting principles.

KPMG
LLP

Chartered Accountants

Calgary, Canada

February 26, 1999

balance sheets

DECEMBER 31 (\$ THOUSANDS)

1998

1997

ASSETS

Current

Cash	\$ 147	\$ 204
Accounts receivable	9,408	8,430
Inventory	2,261	1,912
Investments	125	125

11,941 10,671

Property, plant and equipment (Note 2)

202,348 152,517

\$ 214,289 \$ 163,188

LIABILITIES

Current

Accounts payable and accrued liabilities	\$ 11,258	\$ 13,705
Long-term bank debt (Note 3)	60,986	19,814
Convertible debentures (Note 4)	23,530	23,250
Future abandonment and site restoration costs	2,262	1,661
Deferred income taxes	8,623	6,891

SHAREHOLDERS' EQUITY

Share capital (Note 5)	86,538	78,980
Paid-in capital (Note 4)	2,800	2,800
Retained earnings	18,292	16,087

107,630 97,867

\$ 214,289 \$ 163,188

See accompanying notes.



On Behalf of the Board:
(Director)



(Director)

statements of income

YEAR ENDED DECEMBER 31 (\$ THOUSANDS, EXCEPT PER SHARE)	1998	1997	1996
REVENUE			
Petroleum and natural gas	\$ 39,369	\$ 33,927	\$ 27,911
Royalties, net of Alberta Royalty Tax Credit	(5,519)	(5,802)	(4,258)
	33,850	28,125	23,653
EXPENSES			
Operating	4,894	3,548	3,191
General and administrative	2,430	1,127	1,373
Depletion and depreciation	17,096	11,924	9,496
Interest on long-term debt	4,911	2,854	3,178
	29,331	19,453	17,238
Income before other item and taxes	4,519	8,672	6,415
Gain on sale of investments	-	-	3,738
Income before taxes	4,519	8,672	10,153
Taxes (Note 7)	2,314	4,275	4,035
Net income	\$ 2,205	\$ 4,397	\$ 6,118
Earnings per share	\$ 0.05	\$ 0.11	\$ 0.18
Weighted average number of common shares outstanding	43,644,058	38,522,103	34,347,166

statements of retained earnings

YEAR ENDED DECEMBER 31 (\$ THOUSANDS)	1998	1997	1996
Balance, beginning of year (Note 2)	\$ 16,087	\$ 11,690	\$ 5,572
Net income	2,205	4,397	6,118
Balance, end of year	\$ 18,292	\$ 16,087	\$ 11,690

statements of changes in financial position

YEAR ENDED DECEMBER 31 (\$ THOUSANDS)	1998	1997	1996
Cash provided by (used in)			
Operating activities			
Net income	\$ 2,205	\$ 4,397	\$ 6,118
Items not affecting cash:			
Depletion and depreciation	17,096	11,924	9,496
Deferred income taxes	1,881	3,960	3,774
Amortization of debt discount	280	280	280
Gain on sale of investments	-	-	(3,738)
Cash flow from operations	21,462	20,561	15,930
Change in non-cash working capital related to operations	(979)	570	(472)
	20,483	21,131	15,458
Investing activities			
Property, plant and equipment, net	(66,447)	(49,569)	(23,167)
Site restoration expenditures	(58)	(54)	-
Purchase of investments	-	-	(1,650)
Sale of investments	-	-	5,388
Change in non-cash working capital related to investments	(3,091)	3,583	1,112
	(69,596)	(46,040)	(18,317)
Financing activities			
Common shares, net of issuance costs	7,588	20,797	9,578
Long-term bank debt	41,172	4,290	(7,356)
Change in non-cash working capital related to financing	296	19	72
	49,056	25,106	2,294
Increase (decrease) in cash	(57)	197	(565)
Cash, beginning of year	204	7	572
Cash, end of year	\$ 147	\$ 204	\$ 7

See accompanying notes.

notes to financial statements

December 31, 1998 (in thousands of dollars)

I. SIGNIFICANT ACCOUNTING POLICIES

The financial statements of Petromet Resources Limited (the "Company") have been prepared by management in accordance with generally accepted accounting principles in Canada. The principal accounting policies followed by the Company are summarized below:

(a) Investments

Investments are recorded at the lower of cost and market value.

(b) Inventory

Inventory of equipment is stated at the lower of cost and net realizable value. Cost is determined using the specific item or average cost method.

(c) Property, plant and equipment

(i) *Petroleum and natural gas properties* The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized and accumulated in a single cost centre representing the Company's activity undertaken exclusively in Canada. Such costs include land acquisition costs, geological and geophysical expenses, lease rental costs on non-producing properties, costs of drilling both productive and non-productive wells, related plant and production equipment costs, and overhead charges directly related to these activities.

The provision for depletion and depreciation is determined on the unit-of-production method based on the estimated gross proven reserves as determined by independent engineers. Petroleum and natural gas reserves and production are converted into equivalent units based upon relative energy content. Costs associated with the acquisition and evaluation of significant unproved properties are excluded from amounts subject to depletion until such time as the properties are proved or become impaired. Gas plants and related facilities are depreciated using the straight line method based on the estimated useful life of the assets.

The capitalized costs less accumulated depletion and depreciation are limited to an amount equal to the estimated future net revenue from proven reserves (based on prices and costs at the balance sheet date) plus the unimpaired costs of non-producing properties less estimated future administrative expenses, development costs, financing costs, income taxes and estimated future abandonment and site restoration costs.

The amounts recorded for depletion and depreciation of property, plant and equipment and the provision for future abandonment and site restoration costs are based on estimates. The cost ceiling is based on such factors as estimated proved reserves, production rates, petroleum and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

(ii) *Future abandonment and site restoration costs* Estimated future abandonment and site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Company's engineers based on current regulations, costs, technology and industry standards. The annual charge is included in depletion and depreciation expense and actual abandonment and site restoration expenditures are charged to the accrued liability account as incurred.

(iii) *Joint activities* Substantially all of the exploration and production activities of the Company are conducted jointly with others and accordingly these statements reflect only the Company's proportionate interest in such activities.

(d) Income taxes

The Company follows the deferral method of tax allocation accounting. Under this method, the deferred income tax provision is based on the earnings reported in the accounts and is adjusted for the tax effect of timing differences between financial statement income and taxable income.

(e) Financial instruments

The Company uses forward foreign exchange contracts to reduce its exposure to fluctuations in exchange rates on future domestic sales denominated in US dollars. Gains and losses incurred on forward contracts are recognized with the production revenue to which they relate.

(f) Flow-through shares

The Company has financed a portion of its petroleum and natural gas exploration activities with flow-through share issues. The exploration and development expenditures funded by flow-through share expenditures are renounced to investors in accordance with tax legislation. Petroleum and natural gas properties and share capital are reduced by the estimated cost of the renounced tax deductions when the expenditures are incurred.

(g) Earnings per share

Basic earnings per share is calculated using the weighted average number of common shares outstanding during the year which includes shares reserved for issuance of special warrants. Fully diluted earnings per share is not materially different from basic earnings per share.

2. PROPERTY, PLANT AND EQUIPMENT

	1998	1997
Petroleum and natural gas properties, at cost	\$ 256,081	\$ 189,813
Accumulated depletion and depreciation	53,733	37,296
	\$ 202,348	\$ 152,517

Costs of unproved properties excluded from costs subject to depletion and depreciation at December 31, 1998 were approximately \$13,761 (1997 - \$13,068). Future development costs of proven undeveloped reserves of \$3,479 (1997 - \$9,086) are included in costs subject to depletion and depreciation.

At December 31, 1998, application of the full cost ceiling test did not result in a writedown of capitalized costs.

In 1997, the Company retroactively changed its accounting policy for flow-through shares. Previously, flow-through shares were recorded without adjustment for tax benefits renounced. Petroleum and natural gas properties and share capital are now reduced by the estimated cost of the renounced tax deductions.

3. LONG-TERM BANK DEBT

The bank debt has been advanced under a revolving demand credit facility in the amount of \$75,000 (1997 - \$40,000). The debt bears interest at the bank's prime lending rate, US libor rate plus 0.75 percent or bankers' acceptance rates plus stamping fees. The facility is secured by a \$100,000 floating charge oil and gas debenture but the agreement includes various covenants which influence the amount of additional debt and future security required under certain circumstances. The credit facility is renewable annually, however, no principal repayments are required providing certain reporting and financial covenants continue to be satisfied.

4. CONVERTIBLE DEBENTURES

The 6.5 percent convertible subordinated debentures were issued in 1994 in the principal amount of \$25,000, are due March 31, 2004, with interest paid semi-annually. The debentures are convertible into common shares at \$9.50 per share and are non-redeemable until March 31, 1999, unless the closing price of the common shares for 30 consecutive trading days is \$15.25 per share or more. After March 31, 1999, the debentures are redeemable in the event that the weighted average price at which the common shares are traded during a 30 consecutive trading day period is not less than 130 percent of the conversion price.

5. SHARE CAPITAL

(a) The authorized share capital consists of an unlimited number of common shares and an unlimited number of preference shares, issuable in series. No preferred shares have been issued.

(b) Issued

	SHARES	AMOUNT
Balance, December 31, 1995	33,932,139	\$ 57,226
Issued for flow-through public offering	3,100,000	10,230
Less: issue costs, net of deferred income tax of \$291	-	(361)
Less: effect of tax deductions renounced	-	(1,472)
Balance, December 31, 1996	37,032,139	\$ 65,623
Issued for cash on exercise of stock options	40,000	50
Issued through public offering	2,933,333	11,000
Issued for flow-through public offering	2,716,049	11,000
Less: issue costs, net of deferred income tax of \$557	-	(696)
Less: effect of tax deductions renounced	-	(7,997)
Balance, December 31, 1997	42,721,521	\$ 78,980
Issued for cash on exercise of stock options	1,025,522	2,422
Issued for flow-through private placement	1,567,113	5,500
Less: issue costs, net of deferred income tax of \$149	-	(185)
Less: effect of tax deductions renounced	-	(179)
Balance, December 31, 1998	45,314,156	\$ 86,538

(c) Stock option plan

Stock options to acquire common shares are granted to directors, officers and key employees from time to time at exercise prices equal to the market value of the shares at the date of the grant. At December 31, 1998, options to purchase 2,885,000 common shares were outstanding. Options are granted for a five year term. Options granted prior to July 1, 1997 vested immediately. Options granted thereafter vest over a two year period.

OPTIONS OUTSTANDING

	OPTIONS	PRICE PER SHARE	PROCEEDS IF EXERCISED
Balance, December 31, 1995	3,345,000	\$ 0.31-8.875	\$ 18,402
Granted	415,000	2.80	1,162
Cancelled	(525,000)	4.50-8.875	(4,364)
Balance, December 31, 1996	3,235,000	0.31-8.875	15,200
Granted	815,000	3.00-3.10	2,497
Cancelled	(710,000)	4.50-8.875	(5,733)
Exercised	(40,000)	0.31-2.80	(50)
Balance, December 31, 1997	3,300,000	2.25-8.375	11,914
Granted	1,365,000	3.00-3.95	4,469
Cancelled	(754,478)	2.80-8.375	(4,147)
Exercised	(1,025,522)	2.25-3.15	(2,421)
Balance, December 31, 1998	2,885,000	\$ 2.80-4.50	\$ 9,815
Exercisable, December 31, 1998	2,133,750	\$ 2.80-4.50	\$ 7,393

(d) Flow-through shares

During the year, the Company entered into flow-through share agreements whereby proceeds of \$5,500 were received and the Company committed to expend and renounce \$5,500 in qualified expenditures. Directors and officers of the Company subscribed for 169,913 flow-through shares for consideration of \$610.

6. FINANCIAL INSTRUMENTS

(a) Financial contracts

The Company entered into forward foreign exchange contracts in 1998 to sell US dollars for Canadian dollars. At December 31, 1998 the Company had outstanding contracts to sell \$5,500 US dollars during 1999 at an exchange rate of 1.5281 Canadian. The contracts are matched with fixed sales contracts denominated in US dollars. At year end the cost to the Company to settle these contracts based on quoted forward foreign exchange rates was \$20.

(b) Fair value of financial instruments other than financial contracts

The carrying amounts of cash, accounts receivable, accounts payable and accrued liabilities and bank debt approximate their fair value. The fair value of other financial instruments is based on quoted market prices as follows:

	1998		1997	
	CARRYING VALUE	FAIR VALUE	CARRYING VALUE	FAIR VALUE
Investments	\$ 125	\$ 400	\$ 125	\$ 260
Convertible debentures	23,530	22,000	23,250	22,437

7. TAXES

(a) The income tax expense differs from the amounts which would be obtained by applying the Canadian income tax rate as follows:

	1998	1997	1996
Income tax rate	44.6%	44.6%	44.6%
Expected tax provision	\$ 2,015	\$ 3,868	\$ 4,528
Crown royalties	2,442	2,552	2,040
Non-deductible depletion	650	558	201
Resource allowance	(2,749)	(2,604)	(2,000)
Alberta Royalty Tax Credit	(618)	(542)	(655)
Non-taxable gains	-	-	(458)
Amortization of debt discount	125	125	125
Other	16	3	(7)
Large corporation tax	433	315	261
Provision for taxes	\$ 2,314	\$ 4,275	\$ 4,035

(b) At December 31, 1998, resource properties with a net book value of \$14,900 (1997 - \$15,800; 1996 - \$6,900) have no cost base for income tax purposes. These differences arise primarily as a result of the acquisition of assets with a nominal value for income tax purposes and the issuance of flow-through shares.

(c) At December 31, 1998, the Company has available for deduction against future taxable income, resource deductions and undepreciated capital costs of approximately \$159,000.

8. DIFFERENCES IN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES BETWEEN CANADA AND THE UNITED STATES

The financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP") which, in most respects, conforms to generally accepted accounting principles in the United States ("US GAAP"). The significant differences in those principles, as they apply to the Company, are reflected in the following tables.

Adjustments to report the Company's income in accordance with US GAAP:

	1998	1997	1996
Net income	\$ 2,205	\$ 4,397	\$ 6,118
Adjustments to increase (decrease) income			
Depletion	(1,030)	(947)	(377)
Writedown of petroleum and natural gas properties	(50,000)	-	-
Amortization of debt discount	280	280	280
Income taxes	23,237	447	115
Net income (loss) - US GAAP	(25,308)	4,177	6,136
Other comprehensive income			
Unrealized gain on investments, net of income tax effect	93	10	67
Comprehensive income (loss) - US GAAP	\$ (25,215)	\$ 4,187	\$ 6,203
Earnings (loss) per share - US GAAP	\$ (0.58)	\$ 0.11	\$ 0.18

Balance sheet items adjusted to be in accordance with US GAAP:

	1998		1997	
	CANADIAN GAAP	US GAAP	CANADIAN GAAP	US GAAP
Investments	\$ 125	\$ 400	\$ 125	\$ 260
Property, plant and equipment	202,348	162,418	152,517	163,439
Convertible debentures	23,530	25,000	23,250	25,000
Deferred income taxes	8,623	(3,345)	6,891	17,935
Share capital	86,538	95,816	78,980	88,258
Paid-in capital	2,800	-	2,800	-
Unrealized gain on investments	-	183	-	90
Retained earnings (deficit)	18,292	(17,526)	16,087	7,782

Under US GAAP, the carrying value of petroleum and natural gas properties, net of deferred income taxes, is limited to the present value of future net revenue after tax from proven reserves, discounted at 10 percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. At December 31, 1998, application of the full cost ceiling test under US GAAP resulted in a write down of capitalized costs of \$50,000.

Under US GAAP, the liability method of accounting for income taxes is followed. Deferred income tax assets or liabilities are recorded on the difference between financial statement and income tax bases of assets and liabilities. Deferred income tax provisions are based on the change during the period in the related deferred income tax asset or liability accounts.

Under US GAAP, the reduction of stated capital at December 31, 1992 would not have reduced the deficit. Accordingly, share capital at December 31, 1998 is \$95,816 (1997 - \$88,258).

Under US GAAP, the investments are classified as available for sale securities and are reported at fair value. The unrealized gains and losses, net of related income taxes, are included in comprehensive income and reported as a separate component of shareholders' equity.

Under US GAAP, the paid-in capital component of the convertible debenture is classified as debt on the balance sheet, in accordance with the legal form of the instrument, and the amortization of the debt discount is not reported as an expense in the income statement.

US GAAP requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus other comprehensive income, specifically, all changes in equity during the year arising from transactions and other events from non-owner sources.

In June, 1998, the Financial Accounting Standards Board ("FASB") issued FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement will be effective for the Company's year ending December 31, 2000. The Company is unable to assess the impact of this statement at the present time.

9. UNCERTAINTY DUE TO THE YEAR 2000 ISSUE

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000, and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations. It is not possible to be certain that all aspects of the Year 2000 Issue affecting the entity, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.



five year historical summary

	1998	1997	1996	1995	1994
FINANCIAL (\$ millions, except per share)					
Revenue					
Petroleum and natural gas	\$ 39.4	\$ 33.9	\$ 27.9	\$ 19.1	\$ 9.7
Royalties, net of ARTC	5.5	5.8	4.2	2.4	1.5
	33.9	28.1	23.7	16.7	8.2
Expenses					
Operating	4.9	3.5	3.2	3.2	1.3
General and administrative	2.4	1.1	1.4	1.3	0.6
Depletion and depreciation	17.1	11.9	9.5	7.6	3.1
Interest on long-term debt	4.9	2.9	3.2	3.1	1.8
	29.3	19.4	17.3	15.2	6.8
Income before other items and taxes	4.5	8.7	6.4	1.5	1.4
Gain on sale of investments	-	-	3.7	0.9	-
Income before taxes	4.5	8.7	10.1	2.4	1.4
Taxes					
Current	0.4	0.3	0.2	0.2	0.1
Deferred	1.9	4.0	3.8	0.4	0.4
	2.3	4.3	4.0	0.6	0.5
Net income	\$ 2.2	\$ 4.4	\$ 6.1	\$ 1.8	\$ 0.9
Cash flow from operations	\$ 21.5	\$ 20.6	\$ 15.9	\$ 9.1	\$ 4.6
Balance sheet information					
Capital expenditures, net	\$ 66.4	\$ 49.6	\$ 23.2	\$ 37.9	\$ 57.1
Long-term debt	\$ 84.5	\$ 43.1	\$ 38.5	\$ 45.6	\$ 38.6
Working capital (deficiency)	\$ 0.7	\$ (3.0)	\$ 0.9	\$ 4.6	\$ (2.6)
Shareholders' equity	\$107.6	\$ 97.9	\$ 80.1	\$ 65.6	\$ 34.8
Common shares outstanding (millions)	45.3	42.7	37.0	33.9	26.9
Per share data					
Net income	\$ 0.05	\$ 0.11	\$ 0.18	\$ 0.06	\$ 0.03
Cash flow from operations	\$ 0.49	\$ 0.53	\$ 0.46	\$ 0.29	\$ 0.17
OPERATING					
Production					
Natural gas (mmcf/d)	43.7	37.2	33.1	27.0	12.5
Oil and NGL (bbls/d)	1,329	971	859	801	188
Proven reserves					
Natural gas (bcf)	141.0	167.3	157.4	138.3	125.5
Oil and NGL (mbbls)	3,947	4,674	3,649	3,721	3,067
Proven plus probable reserves					
Natural gas (bcf)	205.1	232.1	207.2	171.1	159.5
Oil and NGL (mbbls)	5,436	6,527	4,559	4,656	3,897
Wells drilled					
Gross	14	31	29	24	40
Net	12	25	21	18	24

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbl	barrel
bbls	barrels
bcf	billions of cubic feet
bcfe	billions of cubic feet equivalent
BOE	barrels of oil equivalent (10 mcf = 1 bbl)
mbbls	thousands of barrels
mboe	thousands of barrels of oil equivalent
mcf	thousands of cubic feet
mcfe	thousands of cubic feet equivalent (1 bbl = 10 mcf)
mmbbls	millions of barrels
mmboe	millions of barrels of oil equivalent
mmbtu	millions of British Thermal Units
mmcf	millions of cubic feet
mmcfe	millions of cubic feet equivalent
NGL	natural gas liquids
WTI	West Texas Intermediate

CORPORATE INFORMATION

Directors⁺

Edmond G. Eberts*†
President, RAPPORT Capital
Formation Strategists Inc.
Toronto, Ontario

David H. Erickson■
Businessman
Calgary, Alberta

Charles J. Howard*
President, Ausnoram Holdings Limited
Toronto, Ontario

Johannes J. Nieuwenburg
President & Chief Executive Officer
Calgary, Alberta

Christopher W. Nixon†
Partner, Osler, Hoskin & Harcourt

P. Grenville Schoch†
Chairman of the Board
Toronto, Ontario

Laurie J. Smith*■
Businessman
Calgary, Alberta

Sharon A. Supple■
Chief Financial Officer
Calgary, Alberta

* Member, Audit Committee

† Member, Management Compensation Committee

+ Directors are elected annually

■ Not standing for re-election

Officers

P. Grenville Schoch
Chairman of the Board

Johannes J. Nieuwenburg
President & Chief Executive Officer

Sharon A. Supple
Chief Financial Officer

Blaine D. Holstein
Vice President, Operations

Christopher W. Nixon
Secretary

Registered Office

Suite 6600, 1 First Canadian Place
P.O. Box 50
Toronto, Ontario M5X 1B8

Executive Office

Suite 350, 839 - 5 Avenue S.W.
Calgary, Alberta T2P 3C8
Telephone: (403) 269-2627
Fax: (403) 269-3922

Legal Counsel

Osler, Hoskin & Harcourt
Calgary and Toronto

Banker

Royal Bank of Canada, Calgary

Transfer Agent and Registrar

CIBC Mellon Trust Company
Calgary and Toronto

Auditors

KPMG LLP, Calgary

Listed

The Toronto Stock Exchange
Common share symbol: PNT
Convertible debenture symbol: PNT.DB

The Nasdaq Stock Market
Common share symbol: PNTGF

Website

www.petromet.com

Email

corp@petromet.com

ANNUAL INFORMATION FORM

Copies of the Company's Annual Information Form are available upon request.



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